APPENDIX B

CODE OF CONDUCT

GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF PEC, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC AND PEC

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of each other and DEC and PEC are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information: Nonpublic information that pertains to Electric Services provided by DEC or PEC, including but not limited to information concerning electric generation, transmission, distribution, or sales.

Customer: Any retail electric customer of DEC or PEC in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC or PEC in connection with the supplying of Electric Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC and PEC, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or PEC from sources other than DEC or PEC for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good and service supplied by DEC or PEC, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good and service supplied to DEC or PEC, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good and service supplied by DEC and PEC to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's and PEC's most recent general rate case proceedings.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission on June 22, 2011, and as amended and refiled on June 12, 2012, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Progress Energy.

Natural Gas Services: Natural gas sales and natural gas transportation, and other related services, including, but not limited to, metering and billing.

Nonpublic Utility Operations: All business operations engaged in by DEC or PEC involving activities (including the sales of goods or services) that are not regulated by the Commission, or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS and PESC, other than a Utility Affiliate, DEC, or PEC.

PEC: Progress Energy Carolinas, Inc., the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territory of PEC and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Personnel: An employee or other representative of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

PESC: Progress Energy Services Company and its successors, which is a service company Affiliate that provides Shared Services to PEC, DEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, individually or in combination.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of PEC, and which became a subsidiary of Duke Energy after the close of the Merger, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC or PEC to take from DEBS or PESC pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, Inc. (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), and Florida Power Corporation, d/b/a Progress Energy Florida (PEF); and the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC and PEC, to the extent such relationships, activities, and transactions affect the operations or costs of utility service experienced by the public utility operations of DEC and PEC in their respective service areas. DEC, PEC, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 998, and E-7, Sub 986. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry; or other changes that warrant modification of this Code.

DEC or PEC may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that exigent circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, PEC, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable. DEC, PEC, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's and PEC's Nonpublic Utility Operations shall maintain separate records from those of DEC's and PEC's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC and PEC may provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation under the same terms and conditions that such information is provided to non-Affiliates.

(b) Except as provided in Section III.A.2.(f) below, Customer Information shall not be disclosed to any person or company, without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be obtained by means of written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC and PEC retain such authorization for verification purposes for as long as the authorization remains in effect.

(c) If the Customer allows or directs DEC or PEC to provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, then DEC or PEC shall ask the Customer if he, she, it would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC or PEC to provide Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Sections III.A.2.(a), 2.(b), and 2.(c) herein shall be permanently posted on DEC's and PEC's website.

(e) No DEC or PEC employee who is transferred to Duke Energy or another Affiliate will be permitted to copy or otherwise compile any Customer Information for use by such entity except pursuant to written permission from the Customer, as reflected by a signed Data Disclosure Authorization. Neither DEC nor PEC shall transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions established by this Section III.A.2, DEC and PEC may disclose Customer Information to DEBS, PESC, any other Affiliate, a Nonpublic Utility Operation or a non-affiliated third party without Customer consent, but only to the extent necessary for the Affiliate, Nonpublic Utility Operation or non-affiliated third party to provide goods or services to DEC or PEC and upon their explicit agreement to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(g) DEC and PEC shall take appropriate steps to store Customer Information in such a manner as to limit access to only those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC and PEC shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS or PESC employee may use Customer Information to market or sell any product or service to DEC's or PEC's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC or PEC.

(j) DEBS and PESC employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS or PESC that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of the Utilities.

(k) Should any inappropriate disclosure of DEC or PEC Customer Information occur at any time, DEC or PEC is required to promptly file a statement with the Commission in this docket describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

3. The disclosure of Confidential Systems Operation Information of DEC and PEC (referred to hereinafter as "Information") shall be governed as follows:

(a) Such Information shall not be disclosed by DEC or PEC to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required when disclosure to Affiliates or Nonpublic Utility Operations meets one of the following exceptions:

(i) The Information is provided to employees of DEC or PEC for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998;

(ii) The Information is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements;

(iii) A state or federal regulatory agency or court having jurisdiction over the disclosure of the Information requires the disclosure;

(iv) The Information is provided to employees of DEBS or PESC pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153;

(v) The Information is provided to employees of DEC's or PEC's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service;

(vi) The Information is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of Information to be disclosed;

(vii) Disclosure is otherwise essential to enable DEC or PEC to provide Electric Services to their Customers; or

(viii) Disclosure of the Information is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any Information disclosed pursuant to the exceptions in Section III.A.3(a), above, shall be disclosed only to employees that need the information for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such Information must be prohibited from acting as conduits to pass the Information to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such Information.

(c) For disclosures pursuant to exceptions (vii) and (viii) in Section III.A.3(a), above, DEC and PEC shall include in their annual affiliated transaction reports the following information:

(i) The types of Information disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, PEC, DEBS, and PESC employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and PEC.

(e) Should the handling or disclosure of Market Information, Transmission Information, or other CSOI by DEBS, PESC, or another Affiliate or Nonpublic Utility Operation, or their respective employees, result in (i) a violation of DEC's or PEC's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an OASIS or other Internet website, or (iii) other public disclosure of the data, DEC or PEC shall promptly file a statement with the Commission in Commission in Docket Nos. E-7, Sub 986C, and E-2, Sub 998C, respectively, describing the circumstances leading to such violation, posting, or other this docket describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the mitigating and/or other steps taken to address the current or any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC or PEC shall promptly file a statement with the Commission in Docket Nos. E-7, Sub 986C, or E-2, Sub 998C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and PEC shall file a letter in Docket Nos. E-7, Sub 986E, and E-2, Sub 998E, with the Commission describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's and PEC's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, neither DEC nor PEC shall provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, nor to any customers of such an entity, as compared to non-Affiliates or

their customers. Moreover, neither DEC, PEC, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC and PEC shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC and PEC shall process all similar requests for Electric Services in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, PEC, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC or PEC; provided however, that this prohibition shall not apply to employees of DEBS or PESC providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or PEC's regulated public utility operations.

6. No personnel or representatives of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. Neither DEC nor PEC shall condition or otherwise tie the provision or terms of any Electric Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC or PEC receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2 of this Code of Conduct.

C. Marketing

1. The public utility operations of DEC and PEC may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Utility Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. Neither DEC nor PEC shall otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

(a) "[Duke Energy Corporation/Affiliate) is not the same company as [DEC/PEC], and [Duke Energy Corporation/Affiliate) has separate management and separate employees";

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/PEC]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/PEC]."

3. Nonpublic Utility Operations may not use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

(a) "[Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/PEC] and is not in any way sanctioned by the North Carolina Utilities Commission";

(b) "Purchasers of products or services from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/PEC]"; and

(c) "A customer does not have to buy products or services from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/PEC]."

The required disclaimer must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC or PEC and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC or PEC for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. As a general guideline, with regard to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC or PEC, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's or PEC's operations or costs of utility service, the following conditions shall apply:

(a) Except as otherwise provided for in this Section III.D, for untariffed goods and services provided by DEC or PEC to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC or PEC shall be set at the higher of Market Value or DEC's or PEC's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D, for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS or PESC, or a Nonpublic Utility Operation to DEC or PEC, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC or PEC shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC or PEC do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC and PEC shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's and PEC's Customers receive service at the lowest reasonable cost. For goods and services provided by DEBS and PESC to DEC, PEC, and Utility Affiliates, the transfer price charged shall be set at DEBS' and PESC's Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC and PEC to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services (such as time of use, manner of use, customer class, load factor, and relevant Standard Industrial Classification) under the applicable tariff.

(d) Subject to and in compliance with all conditions placed upon DEC and PEC by the Commission, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC or PEC to DEC, PEC, or the Utility Affiliates or by the Utility Affiliates to DEC or PEC, shall be transferred at the supplier's Fully Distributed Cost.

4. To the extent that DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS or PESC (or their successors), these Shared Services may be jointly provided to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC and PEC is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC and PEC. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual(s) filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, PEC, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of natural gas, coal, and electricity or ancillary services intended for resale), if such joint purchases result in cost savings to DEC's and PEC's Customers. DEC, PEC, Duke Indiana, Duke Kentucky, and PEF, may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's and PEC's Customers. Notwithstanding the foregoing, if any of the coal or natural gas jointly purchased by DEC, PEC, Duke Indiana, Duke Kentucky, or PEF is transferred to or utilized by another Affiliate within 12 months of the joint purchase, DEC and PEC will file a notification of such with the Commission. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's and PEC's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manuals required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North

Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC and PEC incur in assembling, compiling, preparing, or furnishing requested Customer Information or Confidential Systems Operation Information for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates shall be recovered from the requesting party pursuant to Section III.D.3 of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC or PEC in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission; provided however, that DEC and PEC are not required to provide advance notice for such transfers to each other. DEC and PEC may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC and PEC shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The State's existing requirements regarding affiliate transactions, as set forth in G.S. 62-153, shall continue to apply to all transactions between DEC, PEC, Duke Energy, and the other Affiliates.

2. The books and records of DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC or PEC with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or PEC to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or PEC shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC and PEC, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes any charges to Customers for Electric Services and non-Electric Services from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for the Electric Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC and PEC shall establish complaint procedures to resolve potential complaints that arise due to the relationship of DEC and PEC with Duke Energy, its other Affiliates, and its Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC or PEC.

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC or PEC shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC and PEC shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1, any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint or otherwise address questions to the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/PEC CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/PEC's Affiliates offer products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes DEC/PEC to provide any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) ______________________. DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/PEC offers optional, market-based products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes DEC/PEC to use any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

Attachment A

Duke-Progress Merger
Docket No. E-2, Sub 998, and E-7, Sub 986
Computation of FERC Mitigation Capacity Cost Decrement
NC Retail Operations

Line No	Item		DEC	PEC
1.	NC Retail Mitigation Capacity Allocation	1/	$30,286,447	$14,510,546
2.	Forecast NC Retail kWh Sales	2/	165,977,270,402	112,075,177,338
3.	Decremental $/kWh Sales		$0.000182	$0.000129
4.	Billing Adj. - NC GRT and Reg. Fee		1.034554	1.034554
5.	Proposed NC Retail Rider $/kWh		$0.000189	$0.000134

Footnotes:
1/ Based on Stipulated Methodology.
2/ Based on September 2011 IRP Filings.

METHODOLOGY FOR CALCULATING COAL BLENDING SAVINGS

Savings through coal blending will be determined by multiplying the number of tons of non-traditional coal actually delivered to the plants that are retrofitted by DEC for the purpose of coal blending after the close of the Merger by the difference between the delivered price per MMBtu of avoided traditional coal minus the delivered price per MMBtu of purchased non-traditional coal. This price comparison of the avoided cost of a traditional coal to the purchase price of a non-traditional coal will be performed at the time of the coal purchase covering the entire term of the coal contract and will remain constant.

The term “traditional coal” is defined as coal from Central Appalachia (CAPP) or another source that is of a similar heat content, fusion temperature, ash, and sulfur content as CAPP coal and has been or could have been used in DEC’s generating plants without blending, or modification of the boiler feed, ash handling, combustion control systems, or other modification over and above the addition of scrubbers. “Non-traditional coal” is defined as all coal other than traditional coal.

<u>Contracted Coal Purchases</u>

Step 1: At the time that DEC enters into a contract for non-traditional coal, DEC will identify the number of tons under contract and the delivered cost per MMBtu of that contracted-for non-traditional coal (referred to as “A” in Step 3, below). The delivered cost per MMBtu will include an estimate of the transportation cost of the non-traditional coal for the duration of the contract.

Step 2: At the time that DEC enters into a contract for non-traditional coals, DEC will concurrently determine the delivered price per MMBtu for avoided purchases of the traditional coal replaced by the purchase of non-traditional coal. The delivered cost per MMBtu will include an estimate for the cost of transporting the traditional coal for the duration of the non-traditional coal contract. When calculated as part of a Request for Proposals (RFP), the delivered price per MMBtu for the avoided purchases of traditional coal is the weighted average price of the avoided purchases of traditional coal, determined as follows:

(a) The lowest delivered price per MMBtu for traditional coal and its related volume that was not purchased is identified. (See Exhibit 1.)

(b) If the tons related to the first offer are greater than the tons of non-traditional coals purchased from the RFP, then no additional traditional coals are selected.

(c) If the tons are less than the non-traditional tons purchased, then the next lowest delivered price per MMBtu for traditional coal is selected and this process repeats until the tonnage of traditional coals that were not contracted is equal to the tonnage of non-traditional coal to be purchased pursuant to contract.

(d) The weighted average delivered price per MMBtu of traditional coals is then calculated using this list of coals covering each specific month or year of the term of the coal contract (referred to as "B" in Step 3, below.

Step 3: The traditional coal delivered price per MMBtu [B] minus the non-traditional delivered price per MMBtu [A] provides the unit cost savings over the term of the contract and remains constant. (See Exhibit 2). This unit cost savings is multiplied by the tons, as they are actually delivered to DEC plants over the specified contract term and produce realized savings. Exhibit 3 provides a detailed example of the savings calculation over the term of a theoretical contract.

Spot Market Coal Purchases

Periodically, short-term spot coal purchases are made outside of an RFP process. Any non-traditional coal purchased outside an RFP process will follow the same principles described above except instead of using the actual cost of traditional coals displaced under the RFP, a substituted market cost determined from a third party industry-acknowledged source will be used.

139 FERC ¶ 61,194
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Duke Energy Corporation Progress Energy, Inc.	Docket No. EC11-60-004
Carolina Power & Light Company	Docket No. ER12-1339-000 Docket No. ER12-1340-000 Docket No. ER12-1341-000
Duke Energy Carolinas, LLC	Docket No. ER12-1342-000 (Not consolidated)

ORDER ACCEPTING
REVISED COMPLIANCE FILING, AS MODIFIED,
AND POWER SALES AGREEMENTS

(Issued June 8, 2012)

1. On March 26, 2012, Duke Energy Corporation (Duke Energy) and Progress Energy, Inc. (Progress Energy) (together, with their public utility subsidiaries, Applicants) filed a revised compliance filing[1] in accordance with the Commission's December 14, 2011 order[2] rejecting Applicants' previously filed compliance proposal.[3] Concurrently with the March 26 Compliance Filing, Applicants filed four related power

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[1] *Revised Compliance Filing of Duke Energy Corporation and Progress Energy, Inc.*, Docket No. EC11-60-004 (March 26, 2012) (March 26 Compliance Filing).

[2] *Duke Energy Corp.*, 137 FERC ¶ 61,210 (2011) (Compliance Order), *rehearing pending*.

[3] *Compliance Filing of Duke Energy Corporation and Progress Energy, Inc.*, Docket No. EC11-60-001 (October 17, 2011) (October 17 Compliance Filing).

sales agreements pursuant to section 205 of the Federal Power Act (FPA).[4] This order accepts the March 26 Compliance Filing and the four power sales agreements subject to Applicants revising their mitigation proposal as described in further detail below.

I. Background

2. On April 4, 2011, pursuant to sections 203(a)(1) and 203(a)(2) of the FPA[5] and Part 33 of the Commission's regulations,[6] Applicants filed an application for the approval of a transaction pursuant to which Progress Energy would become a wholly-owned subsidiary of Duke Energy and the former shareholders of Progress Energy would become shareholders of Duke Energy (Proposed Transaction).[7]

3. Subsequent to the filing of the Merger Application, the Director of the Division of Electric Power Regulation-West issued a request for additional information from

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[4] 16 U.S.C. § 824d (2006). As described in further detail below, Applicants propose that the four power sales agreements serve as interim mitigation while the transmission expansion projects proposed as permanent mitigation are completed. In addition to being filed for approval under section 205 of the FPA, the four power sales agreements were included as attachments to the March 26 Compliance Filing. *Master Power Purchase and Sale Agreement between Carolina Power & Light, d/b/a Progress Energy Carolinas, Inc. and EDF Trading North America, LLC*, Docket No. ER12-1339-000 (March 26, 2012); *Master Power Purchase and Sale Agreement between Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. and Cargill Power Markets, LLC*, Docket No. ER12-1340-000 (March 26, 2012); *Master Power Purchase and Sale Agreement between Carolina Power & Light d/b/a Progress Energy Carolinas, Inc. and Morgan Stanley Capital Group Inc.*, Docket No. ER12-1341-000 (March 26, 2012) (PEC-Morgan Stanley Filing); and *Power Purchase and Sale Agreement between Duke Energy Carolinas, LLC and Cargill Power Markets, LLC*, Docket No. ER12-1342-000 (March 26, 2012) (collectively, Power Sales Agreement Filings). In this order, the Commission refers to Carolina Power & Light, a subsidiary of Progress Energy, as Progress Energy Carolinas.

[5] 16 U.S.C. §824b(a)(1) and (a)(2) (2006).

[6] 18 C.F.R. Part 33 (2011).

[7] *Application for Authorization of Disposition of Jurisdictional Assets and Merger under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act*, Docket No. EC11-60-000 (Apr. 4, 2011) (Merger Application).

Applicants.[8] In the August 2011 Information Request, Applicants were directed to provide additional analyses and information that was not provided in the Merger Application.[9] Among other things, the August 2011 Information Request directed Applicants to produce a set of prices based on EQR data, and, using those prices, conduct a DPT of the base case and two price sensitivities (a 10 percent price increase and a 10 percent price decrease) for the Duke Energy Carolinas, Progress Energy Carolinas-East, and Progress Energy Carolinas-West Balancing Authority Areas (BAA).[10] In response to the August 2011 Information Request, Applicants submitted a DPT based on EQR data (August 29 DPT) as directed.[11]

4. The Commission reviewed the Merger Application pursuant to the Commission's Merger Policy Statement[12] and found that, in the absence of appropriate mitigation, the

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[8] Request for Additional Information, Docket No. EC11-60-000 (Aug. 22, 2011) (August 2011 Information Request).

[9] As noted in the Commission's initial order on the Merger Applicants, Applicants did not provide a Delivered Price Test (DPT) based on prices derived from Electric Quarterly Reports (EQR) data with the Merger Application. The DPT submitted with the Merger Application was based on system lambda price proxies (Merger Application DPT). *Duke Energy Corp.*, 136 FERC ¶ 61,245, at P 47 (2011) (Merger Order), *rehearing pending*. DPTs are used to determine the pre- and post-transaction market shares from which the market concentration or Herfindahl-Hirschman Index (HHI) change can be calculated. In this order, the terms DPT, Competitive Analysis Screen, and Appendix A Analysis are used interchangeably.

[10] As explained in the Merger Order, Applicants focused their analysis on these BAAs. *See* Merger Order, 136 FERC ¶ 61,245 at P 37.

[11] Answer of Duke Energy Corporation and Progress Energy, Inc. to Request for Additional Information, Docket No. EC11-60-000 (Aug. 29, 2011, corrected Aug. 30, 2011) (Applicants August 29 Answer). Although the August 29 DPT differs from the Merger Application DPT with respect to the source of the forecasted 2012 prices, Applicants adjusted both the system lambda and EQR prices used in the Merger Application and August 29 DPTs, respectively, by a common natural gas price forecast.

[12] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, 72 Fed. Reg. 42,277 (Aug. 2, 2007), FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Revised Filing Requirements Under Part 33 of the*

(continued…)

Proposed Transaction could be expected to result in adverse effects on competition in both the Duke Energy Carolinas and the Progress Energy Carolinas-East BAAs.[13] The Commission thus conditionally authorized the Proposed Transaction subject to Commission approval of market power mitigation measures. The Commission explained that these mitigation measures could include, but were not limited to: "joining or forming a [Regional Transmission Organization (RTO)], implementation of an independent coordinator of transmission (ICT) arrangement, generation divestiture, virtual divestiture, and proposals to build new transmission to provide greater access to third party suppliers."[14] The Commission stated that if Applicants wished to proceed with the Proposed Transaction, they were directed to make a compliance filing within 60 days of the Merger Order proposing mitigation that would be sufficient to remedy the screen failures discussed in the Merger Order.[15]

5. Applicants responded to the Merger Order by proposing mitigation. Specifically, in the October 17 Compliance Filing, Applicants submitted a mitigation proposal that they stated adopted the virtual divestiture option listed in the Merger Order (Prior Mitigation Proposal). Applicants explained that the Prior Mitigation Proposal consisted of a "must offer" obligation for Applicants to "sell specific quantities of energy at cost-based rates to entities that serve load, directly or indirectly" in the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs.[16]

6. According to Applicants, the product that they proposed to offer for sale, referred to as AEC Energy, replicated the Available Economic Capacity (AEC) product analyzed by the Commission in the August 29 DPT and would be offered to be sold pursuant to Applicants' existing cost-based tariffs and under standard and reasonable terms for sales

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Commission's Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000) (Order No. 642), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). *See also Transactions Subject to FPA Section 203,* Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

[13] Merger Order, 136 FERC ¶ 61,245 at PP 1, 117.

[14] Merger Order, 136 FERC ¶ 61,245 at P 146.

[15] Merger Order, 136 FERC ¶ 61,245 at P 145. The Commission explained that after providing an opportunity for comments from interested parties, it would issue a subsequent order indicating whether the proposed mitigation was sufficient.

[16] October 17 Compliance Filing at 3.

of this type of product.[17] Applicants proposed that the must offer obligation apply in the Duke Energy Carolinas BAA in the summer and winter seasons, and in the Progress Energy Carolinas-East BAA in the summer season.[18] Applicants stated that the AEC Energy would be offered on a day-ahead basis, and eligible purchasers would be limited to entities ultimately serving load located in the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs. In addition, the energy purchased would be required to sink in the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs.[19] Applicants proposed to offer the AEC Energy at the "forecasted average incremental cost (after serving retail and wholesale native load and existing (as of the date the merger closes) firm obligations) of [Applicants] plus [ten percent]."[20] Finally, Applicants proposed to engage an independent monitoring entity to ensure that they were in compliance with the Prior Mitigation Proposal and that the Prior Mitigation Proposal last for a term of eight years.

7. In the Compliance Order, the Commission rejected the Prior Mitigation Proposal, finding that it did not "remedy the Proposed Transaction's adverse effects on competition, including screen failures, identified in the Merger Order."[21] The Commission continued to find that the Proposed Transaction, as initially submitted by Applicants and supplemented by the Prior Mitigation Proposal, would have an adverse effect on competition. The Commission stated that the Proposed Transaction remained "conditionally authorized, subject to Commission approval of market power mitigation measures that remedy the screen failures identified in the Merger Order."[22] The Commission concluded that until Applicants corrected the adverse effects of the Proposed Transaction, the Commission could not unconditionally authorize it.

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[17] October 17 Compliance Filing at 3.

[18] October 17 Compliance Filing at 3.

[19] October 17 Compliance Filing at 5-6.

[20] October 17 Compliance Filing at 5.

[21] Compliance Order, 137 FERC ¶ 61,210 at P 66.

[22] Compliance Order, 137 FERC ¶ 61,210 at P 66.

8. As discussed in further detail below, the March 26 Compliance Filing contains Applicants' revised proposal for mitigating the screen failures identified by the Commission in the Merger Order.[23]

II. <u>Notice of Filings and Responsive Pleadings</u>

A. <u>March 26 Compliance Filing</u>

9. Notice of the March 26 Compliance Filing was published in the *Federal Register*, 77 Fed. Reg. 20,016 (2012), with comments due on or before April 25, 2012.

10. On January 23, 2012, Richard Bickel; Apalachicola Area Historical Society, Inc.; Dr. Helen E.A. Tudor; Tom Brocato; George Cloon; Leon Bloodworth; Michael and Catherine Bailey; Robert Lindsley, and Susan Buzzett Clementson (collectively, Apalachicola Intervenors) filed a motion to intervene and protest of the Proposed Transaction.[24]

11. On April 6, 2012, Richard Allen and fifty-one others filed protests generally opposing the Proposed Transaction. Donald and Barbara Lilenfeld filed similar protests on May 3, 2012.

12. On April 10, 2012, the Director of the Division of Electric Power Regulation-West issued a request for additional information from Applicants.[25]

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[23] Applicants' newly proposed mitigation is referred to in this order as the Revised Mitigation Proposal.

[24] Apalachicola Intervenors, Amended Motion to Intervene and Protest of the Merger Between Duke Power and Progress Energy, Docket Nos. EC11-60-001, ER12-115-000, ER12-116-000, ER12-118-000, ER12-119-000, ER12-120-000, ER11-3306-000, and ER11-3307-000 (not consolidated) (Jan. 23, 2012) (Apalachicola Protest). On February 13, 2012, Apalachicola Intervenors filed the Second Amended Motion to Intervene and Protest of the Merger Between Duke Power and Progress Energy in the same dockets as the Apalachicola Protest. The two motions appear to be identical and Apalachicola Intervenors do not explain how the two motions differ, if at all.

[25] Request for Additional Information, Docket No. EC11-60-004 (Apr. 10, 2012) (April 2012 Information Request).

13. On April 13, 2012, Applicants filed a response to the April 2012 Information Request.[26] Notice of Applicants April 13 Information Request Answer was published in the *Federal Register*, 77 Fed. Reg. 24,481 (2012), with comments due on or before April 25, 2012.

14. On April 16, 2012, April 30, 2012, and May 7, 2012, Robert McManus filed comments regarding the Revised Mitigation Proposal.

15. On April 20, 2012, the City of Orangeburg, South Carolina (City of Orangeburg), filed a motion to consolidate Docket No. EC11-60-004, the Revised Mitigation Proposal docket, and the Power Sales Agreement Filings dockets, Docket Nos. ER12-1339-000, ER12-1340-000, ER12-1341-000, ER12-1342-000.[27] On the same day, City of Orangeburg filed comments on the Revised Mitigation Proposal.[28]

16. On April 25, 2012, the Florida Municipal Power Agency (FMPA),[29] and the Cities of New Bern and Rocky Mount, North Carolina (City of New Bern)[30] filed protests

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[26] Answer of Duke Energy Corporation and Progress Energy, Inc., Docket No. EC11-60-004 (Apr. 13, 2012) (Applicants April 13 Information Request Answer).

[27] Motion to Consolidate of the City of Orangeburg, South Carolina, Docket Nos. EC11-60-004, ER12-1339, ER12-1340-000, ER12-1341-000, and ER12-1342-000 (not consolidated) (April 20, 2012) (City of Orangeburg Motion to Consolidate).

[28] Comments of the City of Orangeburg, South Carolina on Applicants' Second Mitigation Proposal and Request for Relief or, in the Alternative, Request for Hearing, Docket No. EC11-60-004 (April 20, 2012) (City of Orangeburg Comments on Revised Mitigation Proposal).

[29] FMPA Protest of Duke Energy and Progress Energy Revised Compliance Filing, Docket No. EC11-60-004 (Apr. 25, 2012) (FMPA Protest of Revised Mitigation Proposal).

[30] Protest of the Cities of New Bern and Rocky Mount, North Carolina Concerning Applicants' Revised Compliance Filing, Docket No. EC11-60-004 (Apr. 25, 2012), as corrected by Errata to Protest of the Cities of New Bern and Rocky Mount, North Carolina Concerning Applicants' Revised Compliance Filing (Apr. 25, 2012), EC11-60-004 (collectively, City of New Bern Protest of Revised Mitigation Proposal).

regarding the Revised Mitigation Proposal. The Electric Power Supply Association (EPSA) also filed comments April 25, 2012.[31]

17. On May 1, 2012, Applicants filed an answer to the protests.[32] On May 4, 2012, City of Orangeburg filed an answer to Applicants May 1 Answer.[33] On May 7, 2012, Public Staff-North Carolina Utilities Commission (North Carolina Commission Staff) filed an answer in opposition to the City of Orangeburg May 4 Answer.[34] On May 9, 2012, Applicants filed a supplement to their May 1 Answer.[35] On May 11, 2012, City of Orangeburg filed a supplement to its May 4 answer.[36] On May 14, 2012, City of New Bern filed a motion to strike portions of Applicants May 1 Answer and Applicants May 9 Supplement.[37]

B. The Power Sales Agreement Filings

18. Notices of the Power Sales Agreement Filings were published in the *Federal Register*, 77 Fed. Reg. 20,016 (2012), with comments due on or before April 16, 2012.

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[31] Comments of the Electric Power Supply Association, Docket No. EC11-60-004 (Apr. 25, 2012) (EPSA Comments on Revised Mitigation Proposal).

[32] Answer of Duke Energy Corporation and Progress Energy, Inc,, Docket Nos. EC11-60-004, ER12-1339-000, ER12-1340-000, ER12-1341-000, and ER12-1342-000 (not consolidated) (May 1, 2012) (Applicants May 1 Answer).

[33] Answer of the City of Orangeburg, South Carolina to the Answer of Duke Energy Corporation and Progress Energy, Inc., EC11-60-004 (May 4, 2012) (City of Orangeburg May 4 Answer).

[34] Answer of the Public Staff-North Carolina Utilities Commission in Opposition to Comments and Requests for Relief of the City of Orangeburg, South Carolina Regarding Applicants' Revised Compliance Filing, Docket No. EC11-60-004 (May 7, 2012) (North Carolina Commission Staff May 7 Answer).

[35] Supplement to Answer of Duke Energy Corporation and Progress Energy, Inc., Docket No. EC11-60-004 (May 9, 2012) (Applicants May 9 Supplement).

[36] Supplemental Answer of City of Orangeburg, South Carolina, Docket No. EC11-60-004 (May 11, 2012) (City of Orangeburg May 11 Supplement).

[37] Motion of the City of New Bern and Rocky Mount to Strike or Disregard Portions of Applicants' Answer and Supplement and Accompanying Exhibits, Docket No. EC11-60-004 (May 14, 2012) (City of New Bern Motion to Strike).

19. Timely motions to intervene in Docket Nos. ER12-1339-000, ER12-1340-000, ER12-1341-000, ER12-1342-000 were filed by North Carolina Electric Membership Corporation; the Attorney General of the State of North Carolina and North Carolina Commission Staff; City of Orangeburg; and Carolina Electric Membership Corporations (Carolina EMCs).[38]

III. Procedural Matters

20. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2011), we will grant Apalachicola Intervenors' motion to intervene in the compliance proceeding in Docket No. EC11-60-004. That intervention, however, is limited to Docket No. EC11-60-004 and all future subdockets and does not provide party status with respect to the root docket.[39]

21. With respect to City of Orangeburg's request to consolidate Docket No. EC11-60-004 with the Power Sales Agreement Filings dockets, the Commission declines to do so. As City of Orangeburg notes, in general the Commission consolidates matters only if a trial-type hearing is required to resolve common issues of law and fact, and consolidation will ultimately result in greater administrative efficiency.[40] In this case, we conclude that consolidating this proceeding with the Power Sales Agreement Filings proceedings is not appropriate because there are no issues relating to the Proposed Transaction or the Revised Mitigation Proposal that need to be set for a trial-type evidentiary hearing.

22. We also deny the requests that the Commission set the Revised Mitigation Proposal for hearing.[41] The parties making this request have not demonstrated that there are issues of material fact in dispute that require an evidentiary hearing.[42]

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[38] The Carolina EMCs include Blue Ridge Electric Membership Corporation, Rutherford Electric Membership Corporation, Piedmont Electric Membership Corporation, and Haywood Electric Membership Corporation.

[39] *See, e.g., PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,048, at P 6 (2011). While the Commission grants Apalachicola Intervenors' motion to intervene, their complaints are unrelated to the Proposed Transaction.

[40] *See, e.g., Startrans IO, L.L.C.*, 122 FERC ¶ 61,253, at P 25 (2003); *In re: Terra-Gen Dixie Valley*, 132 FERC ¶ 61,215, at P 44, n.74 (2010).

[41] *See, e.g.*, City of Orangeburg Motion to Consolidate at 4 ("…in the event that the Commission does not summarily reject the [Revised Mitigation Proposal] and grant [City of] Orangeburg the relief sought in the merger docket, the [Power Sales

(continued…)

23. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the answers that have been filed because they have provided information that assisted us in our decision-making process.

IV. The March 26 Compliance Filing

A. The Revised Mitigation Proposal

24. As described in further detail below, the Revised Mitigation Proposal consists of permanent and interim mitigation. According to Applicants, the Revised Mitigation Proposal "provides for permanent structural mitigation in the form of seven transmission expansion projects that fully address the concerns raised by the Commission in the Merger Order."[43] The interim mitigation, which will remain in place for approximately three years while the seven transmission expansion projects are completed, consists of firm sales of capacity and energy pursuant to four power sales agreements with identified buyers (Power Sales Agreements).

1. Permanent Mitigation

25. According to Applicants, the seven transmission expansion projects they are proposing as permanent mitigation will increase transmission import capability into the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs (Transmission Expansion Projects). Applicants note that the Commission identified transmission expansion as an acceptable form of mitigation in the Merger Order, and that the Commission has accepted proposals to mitigate market power through transmission expansion in other cases. Applicants claim that the Transmission Expansion Projects will increase the Simultaneous Transmission Import Limit (SIL) for the Duke Energy Carolinas BAA by 2,440 MW in the summer and 1,930 MW in the winter, and for the Progress Energy Carolinas-East BAA by 2,225 MW in the summer and 1,225 MW in the

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Agreements] and the Revised Mitigation Proposal present questions that are appropriate subjects of discovery and a hearing."), FMPA Protest of Revised Mitigation Proposal at 4 ("…the Commission…should order hearings and discovery and other appropriate procedures").

[42] *See FirstEnergy Corp.*, 133 FERC ¶ 61,222 at P 55 (no hearing is required where no issues of material fact have been identified, even in the presence of market screen failures).

[43] March 26 Compliance Filing at 1.

winter.[44] Applicants note that based on preliminary estimates, the total cost of the Transmission Expansion Projects is projected to be approximately $110 million.[45] Applicants summarize the Transmission Expansion Projects as follows:

Table 1. Transmission Expansion Projects Proposed by Applicants

Project	BAA	Estimated Cost	Time to Construct
Antioch 500/230 kV substation: replace two existing transformers with larger capacity transformers.	Duke Energy Carolinas	$50 million	3 years
Lilesville-Rockingham 230 kV Line: construct new third line.	Progress Energy Carolinas-East	$15.7 million	2 years
Roxboro-E Danville 230 tie: add a series reactor to one Roxboro-E Danville 230 kV line and revise operating procedures.[46]	Progress Energy Carolinas-East	$6.6 million	2 years
Reconductor Kinston Dupont-Wommack 230 kV Line 6-1590 MCM.	Progress Energy Carolinas-East	$18 million	2 years

[44] Applicants also state that the Transmission Expansion Projects will result in increased Available Transfer Capacity (ATC) on paths into the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs. March 26 Compliance Filing at 7.

[45] March 26 Compliance Filing at 8. Applicants state that the preliminary cost estimates are subject to change but that their commitment to build the projects is not affected by any changes in the cost estimates. March 26 Compliance Filing at n.6.

[46] According to Applicants, this project requires the cooperation of American Electric Power, and the Person-Halifax and Wake-Carson projects require the cooperation of Dominion Virginia Power. Applicants state that they have discussed these projects with both companies and that they have entered into memoranda of understanding with them under which both companies have agreed to negotiate binding agreements to undertake the projects. Applicants expect to negotiate and complete binding agreements with American Electric Power and Dominion Virginia Power during the pendency of the Commission's review to ensure the completion of the projects. March 26 Compliance Filing at n.7.

Project	**BAA**	**Estimated Cost**	**Time to Construct**
Person-Halifax 230 kV Line: reconductor Dominion Virginia Power portion of line (20.04 Miles).[47]	Progress Energy Carolinas-East	$16 million	2.5 years
Wake-Carson 500 kV Line: replace existing wave traps with 4000 amp wave traps at both terminals and rework protective relaying.[48]	Progress Energy Carolinas-East	$1.5 million	<2 years
Durham-E. Durham 230 kV line: uprate CT Ratio to 3000 amps.	Progress Energy Carolinas-East	$0.5 million	< 2 years

26. In addition to the Transmission Expansion Projects, Applicants are accelerating the in-service date of Progress Energy Carolinas' already-planned Greenville-Kinston Dupont 230kV Line from 2017 to 2015. Applicants explain that although this line does not, by itself, provide any increase in the Duke Energy Carolinas or Progress Energy Carolinas-East SILs, it is necessary for this line to be in service by 2015 for the last four projects listed in Table 1 to increase the SIL of the Progress Energy Carolinas-East BAA.[49]

27. Applicants assert that, in some of its prior cases involving transmission expansion as mitigation of merger-related market power, "the Commission has required that merger applicants demonstrate 'whether or not the proposed upgrade was foreseeable and reasonably certain.'"[50] According to Applicants, the Commission has held that if an upgrade is foreseeable and reasonably certain to be constructed without the merger, it may not be counted as merger-related market power mitigation. Applicants state that none of the Transmission Expansion Projects is "currently included in either of the Applicants' Transmission Plans," and that while some of the projects have been studied in the past as part of the regional planning process, "there is currently no plan to construct

[47] *See* n.46, *supra*.

[48] *See* n.46, *supra*.

[49] March 26 Compliance Filing at 9.

[50] March 26 Compliance Filing at 9 (*quoting Oklahoma Gas & Electric Co.*, 105 FERC ¶ 61,297, at P 32 (2003) (*OG&E-NRG McClain I*)).

any of them" absent the merger.[51] Applicants conclude that it is not foreseeable and reasonably certain that, absent the Proposed Transaction, the Transmission Expansion Projects would be constructed in the next two to three years.

28. In further support of the Transmission Expansion Projects, Applicants provide the post-transmission expansion DPT results for the Duke Energy Carolinas and Progress-Energy Carolinas-East BAAs for the base case and two price sensitivities discussed in the Merger Order.[52] Applicants state that their analysis demonstrates that the Transmission Expansion Projects "completely mitigate the screen failures in the [Duke Energy Carolinas] BAA identified by the Commission in the Merger Order."[53] Applicants claim that "in most periods, including all periods where there previously were screen failures, the expansion results in a significant *de-concentration* of the market as compared to the pre-merger concentration" in the base case and the price sensitivities.[54] With respect to the Progress Energy Carolinas-East BAA, Applicants state that the Transmission Expansion Projects eliminate the screen failures identified by the Commission in all three market price scenarios (i.e., the base case and two price sensitivities) except for a failure in the base case during the Summer Off-Peak season/load period. During this season/load period, Applicants state that there is an HHI increase of 101 in a moderately concentrated market.[55]

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[51] March 26 Compliance Filing at 10.

[52] March 26 Compliance Filing at 10. *See also* March 26 Compliance Filing, Tables 1 and 2.

[53] March 26 Compliance Filing at 11.

[54] March 26 Compliance Filing at 11 (emphasis in original).

[55] As noted in the Merger Order, 136 FERC ¶ 61,245 at n.316, in the Merger Policy Statement the Commission explained that:

> ...mergers in moderately concentrated markets (with an HHI greater than or equal to 1,000 but less than 1,800) that produce an HHI increase over 100 points potentially raise significant competitive concerns. Mergers in highly concentrated markets (with an HHI of more than 1,800) that produce an HHI increase over 50 points potentially raise significant competitive concerns; if the change in HHI exceeds 100 points it is presumed likely to create or enhance market power.

29. Applicants argue that the screen failure in the Progress Energy Carolinas-East BAA in the Summer Off-Peak season/load period does not raise competitive concerns. Applicants state that the Commission has previously held that "SIL increases greater than the amount of competitive supplies lost due to the merger fully restore the competitive options available to wholesale customers in the BAAs and therefore provide adequate mitigation."[56] Applicants claim that the Transmission Expansion Projects meet this standard. According to Applicants, under the analyses of the Duke Energy Carolinas and Progress Energy Carolinas-East BAAs the Commission relied on in the Merger Order, the largest amount of Progress Energy capacity delivered to the Duke Energy Carolinas BAA was 318 MW in the summer. By comparison, Applicants state that the increase in "'rival capacity' (i.e., the amount of increased capacity not allocated to Duke Energy)" in the Duke Energy Carolinas BAA due to the Transmission Expansion Projects is between 1,900 MW and 2,400 MW in the summer.[57] Based on these increases, Applicants assert that the increases in access to competing supply during the summer are from approximately six to eight times greater than the amount of Progress Energy AEC available to wholesale customers in the Duke Energy Carolinas BAA prior to the Proposed Transaction. Similarly, Applicants state that the analysis relied on by the Commission in the Merger Order also showed at most 543 MW of Duke Energy AEC delivered into the Progress Energy Carolinas-East BAA in the summer, but that the Transmission Expansion Projects would increase access to rival capacity in the summer from 1,300 MW to 2,100 MW. Based on this range of increases, Applicants conclude that the increases in access to competing supply in the Progress Energy Carolinas-East BAA are approximately two to four times greater than the amount of Duke Energy supplies potentially lost as a competitive alternative as a result of the Proposed Transaction.

30. Applicants also assert that the single remaining off-peak screen failure does not represent a systematic market power concern. Noting that the Commission has long recognized that screen failures do not always represent a valid competitive concern, Applicants argue that because the Transmission Expansion Projects will increase import capability by more than four times the amount of competitive supplies lost as a result of the Proposed Transaction, the Transmission Expansion Projects will eliminate any concern that the Proposed Transaction will increase Applicants' ability to withhold

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[56] March 26 Compliance Filing at 12 (*citing Oklahoma Gas & Electric Co.*, 108 FERC ¶ 61,004, at P 32 (2004) (*OG&E-NRG McClain II*); *Oklahoma Gas & Electric Co.*, 124 FERC ¶ 61,239, at P 49 (2008) (*OG&E-Redbud*)).

[57] March 26 Compliance Filing at 13.

output to drive up market prices.[58] Further, Applicants emphasize that the screen failure occurs in the Summer Off-Peak season/load period and only in the base case. According to Applicants, the Commission has held in the past that no competitive concerns were raised even when there were three screen failures occurring in off-peak periods, in contrast to the single failure here, because of the difficulty of withholding the baseload generation that operates in off-peak conditions.[59] Applicants also note the "very small" size of the screen failure and claim that it would be eliminated if Duke Energy supplied only 5 MW less of generation capacity to the Progress Energy Carolinas-East market.

31. Although Applicants conclude that the single failure in the Summer Off-Peak season/load period does not represent a valid competitive concern, they propose "stub mitigation" that would go into effect only if the Commission determines that such mitigation is required.[60] Specifically, if the Commission deems it necessary, Applicants propose to "establish a transmission set-aside of 25 MW of firm transmission capacity from the Duke Energy Carolinas BAA to the Progress Energy Carolinas-East BAA" in the Summer Off-Peak season/load period (Stub Mitigation). Neither Applicants nor any of their affiliates would be able to reserve the 25 MW set-aside on a firm basis.[61] In addition, Applicants state that they have engaged Potomac Economics as an Independent Monitor (Independent Monitor) to monitor compliance with the Stub Mitigation and to file periodic reports with the Commission detailing Applicants' compliance with the proposal.[62]

32. Applicants explain that "[t]he intent of the transmission set-aside alternative is to create the equivalent of a firm transmission right that will be reflected as being unavailable to the Applicants in the allocation of [transmission] capacity from the [Duke Energy Carolinas] BAA to the [Progress Energy Carolinas-East] BAA when performing the competition analysis."[63] Since the Stub Mitigation would prevent Applicants from

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[58] March 26 Compliance Filing at 14-15 (*citing* Supplemental Policy Statement, FERC Stats. & Regs. §31,253 at P 60).

[59] March 26 Compliance Filing at 15 (*citing FirstEnergy Corp.*, 133 FERC ¶ 61,222 at PP 49-50).

[60] March 26 Compliance Filing at 16.

[61] March 26 Compliance Filing at 16.

[62] March 26 Compliance Filing at 18.

[63] March 26 Compliance filing at 16.

entering into firm reservations for the capacity subject to the set-aside, Applicants assert that, for purposes of performing the DPT, it would not be appropriate to allocate any of the set-aside import capacity to Applicants. Instead the capacity would be allocated *pro rata* among all potential suppliers that are unaffiliated with Applicants.[64] Under the Stub Mitigation, after the completion of the Transmission Expansion Projects, Applicants would "set aside 25 MW of import capacity on the [Duke Energy Carolinas] to [Progress Energy Carolinas-East] interface"[65] subject to the following restrictions at all times:

1. If new third party firm transmission reservations are greater than or equal to the 25 MW set-aside amount, then the Applicants may reserve on a firm basis up to the then posted available firm transmission capacity.

2. If new third party firm transmission reservations[66] are less than the 25 MW set-aside amount, then the Applicants shall not reserve on a firm basis any more than the amount of transmission capacity then posted as available on that path for that time which exceeds: (a) 25 MW; less (b) the sum of all new firm third party transmission reservations.[67]

33. Applicants state that they will not claim any kind of native load or other priority over the 25 MW of set-aside capacity, but that, to the extent that the 25 MW of capacity is not reserved by third parties on a firm basis, Applicants and all other market participants will be able to use the capacity in the Summer Off-Peak season/load period on a non-firm basis under the same first-come, first-served rules.[68]

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[64] March 26 Compliance Filing at 16-17.

[65] March 26 Compliance Filing at 17.

[66] Applicants state: "[r]eferences to new third party transmission reservations in this paragraph do not include the amount of existing firm reservations that have been made by third parties and that already have been allocated to third parties under the Competitive Analysis Screen" performed by Applicants' witness. March 26 Compliance Filing at n.13.

[67] March 26 Compliance Filing at 17.

[68] Applicants note that a third party could always reserve import capacity on the set-aside portion of the interface on a firm basis and displace any non-firm use of the set-aside portion of the interface by Applicants. March 26 Compliance Filing at 17.

34. Applicants assert that the Stub Mitigation "is appropriate for treating the interface capacity as unavailable to Applicants" for purposes of the Competitive Analysis Screen.[69] Applicants explain that since they would not be able to make a firm reservation for the capacity that would be set aside, third parties will be entitled to use the entire 25 MW of transmission capacity to deliver their own supplies into the Progress Energy Carolinas-East BAA. Thus, for purposes of the Competitive Analysis Screen, Applicants claim that it is appropriate to allocate the 25 MW of import capacity set aside pursuant to the Stub Mitigation *pro rata* among third parties, and not to Applicants. Applicants state that all remaining unreserved capacity would continue to be allocated on a *pro rata* basis to all parties, including Applicants.[70]

35. In conclusion, Applicants note that although the Commission's regulations do not directly address their set-aside proposal, 18 C.F.R. § 33.3(c)(4)(i)(D)(2), which applies to the allocation of capacity to internal interfaces (as opposed to the allocation of capacity between BAAs, which is the case here), specifically permits merger applicants that have "'committed a portion of the interface capacity to third parties' to avoid the Commission's otherwise applicable rule that all of the capacity of internal interface be allocated to the applicants."[71] Applicants argue that committing a portion of the interface capacity to third parties should similarly allow them to avoid the otherwise applicable rule that the unreserved capacity be allocated *pro rata*.[72] According to Applicants, the Stub Mitigation eliminates the Summer Off-Peak season/load period screen violation in the Progress Energy Carolinas-East BAA.[73]

[69] March 26 Compliance Filing at 17-18.

[70] March 26 Compliance Filing at 18.

[71] March 26 Compliance Filing at 18 (*quoting* 18 C.F.R. § 33.3(c)(4)(i)(D)(2)).

[72] Applicants note that the Commission has accepted the use of redispatch commitments to affect the way that transmission capacity allocations are modeled in merger-related competition analyses. March 26 Compliance Filing at n.14 (*citing OGE-NRG McClain II*, 108 FERC ¶ 61,004 at P 34, *Ameren Services Co.*, 101 FERC ¶ 61,202 at P 32).

[73] March 26 Compliance Filing at 19.

2. **Interim Mitigation**

36. As noted above, Applicants state that it will take from two to three years to construct and place into service the Transmission Expansion Projects.[74] Applicants recognize "that interim mitigation will be required until such time" as the Transmission Expansion Projects are placed into service.[75] Accordingly, Applicants propose "firm sales of capacity and energy" pursuant to the four Power Sales Agreements as interim mitigation (Interim Mitigation Proposal).[76] Applicants assert that the Interim Mitigation Proposal satisfies the concerns that the Commission described in the Compliance Order, and that the firm energy and capacity sales proposed in the March 26 Compliance Filing are "materially different" from those proposed in the Prior Mitigation Proposal.[77]

37. Applicants explain that they have entered into the Power Sales Agreements with Cargill Power Markets, LLC (Cargill), EDF Trading North America, LLC (EDF Trading), and Morgan Stanley Capital Group, Inc. (Morgan Stanley).[78] Applicants describe the material provisions of the Power Sales Agreements, which use "the industry-standard EEI form, as modified by the [Power Sales Agreements],"[79] as follows:

- Applicants will sell energy "on a firm basis in all hours of those seasons when mitigation is required" and in sufficient amounts to fully mitigate the screen failures identified in the Merger Order.[80]

- In the Duke Energy Carolinas BAA, Applicants will sell 150 MW in the Summer Peak season/load period; 300 MW in the Summer Off-Peak season/load period;

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[74] March 26 Compliance Filing at 5.

[75] March 26 Compliance Filing at 19.

[76] March 26 Compliance Filing at 19.

[77] March 26 Compliance Filing at 19.

[78] March 26 Compliance Filing at 20.

[79] March 26 Compliance Filing at 20.

[80] March 26 Compliance Filing at 20.

25 MW in the Winter Peak season/load period; and 225 MW in the Winter Off-Peak season/load period.[81]

- In the Progress Energy Carolinas-East BAA, Applicants will sell 325 MW in the Summer Peak season/load period and 500 MW in the Summer Off-Peak season/load period.[82]

- Applicants will sell the energy on a "must take" basis: the buyers "must take the full contract amounts of energy in all hours, subject to interruption only on *force majeure* grounds."[83] Any interruption of deliveries of energy by Duke Energy Carolinas or Progress Energy Carolinas will result in payment of liquidated damages unless that interruption is excused on *force majeure* grounds.[84]

- The energy sold by Applicants will be sold at a specified price "based on a fixed heat rate and the natural gas price reported in *Platts Gas Daily* for Transco Zone 5."[85] The heat rates will be differentiated between on-peak and off-peak periods and are "based on the heat rates of units that will address the screen failures."[86] The heat rates will be 10.0 MMBtu/MWh for the Summer Peak season/load period; 7.0 MMBtu/MWh for the Summer Off-Peak season/load period; 8.95 MMBtu/MWh for the Winter Peak season/load period; and 7.0 MMBtu/MWh for the Winter Off-Peak seasons/load period.

- The capacity prices, which include negative prices (i.e., in some seasons/load periods, Applicants will pay buyers to take capacity), were "negotiated between

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[81] March 26 Compliance Filing at 20. Cargill will purchase all of the energy and capacity sold in the Duke Energy Carolinas BAA.

[82] March 26 Compliance Filing at 20. In the Progress Energy Carolinas-East BAA, Cargill will purchase 100 MW in both the Summer Peak and Summer-Off Peak season/load periods; EDF Trading will purchase 100 MW in both the Summer Peak and Summer Off-Peak seasons/load periods; and Morgan Stanley will purchase 125 MW and 300 MW in the Summer Peak and Summer-Off Peak seasons/load periods, respectively.

[83] March 26 Compliance Filing at 20. As discussed in further detail below, Applicants have revised the standard *force majeure* clause that would ordinarily apply.

[84] March 26 Compliance Filing at 21.

[85] March 26 Compliance Filing at 20.

[86] March 26 Compliance Filing at 20.

Applicants and the purchasers, at prices that are well below [Duke Energy Carolinas'] and [Progress Energy Carolinas'] cost-based capacity prices."[87]

- There are no restrictions on the use of energy by the purchasers after it is purchased.[88]

- The sales pursuant to the Power Sales Agreements will commence after the merger has closed. The terms of Progress Energy Carolinas' Power Sales Agreements will extend through August 31, 2014; the terms of Duke Energy Carolinas' Power Sales Agreements will extend through February 28, 2015.

38. Applicants claim that the terms of the Power Sales Agreements address the Commission's concerns with the Prior Mitigation Proposal that the Commission identified in the Compliance Order. Applicants explain that in the Compliance Order, the Commission found that the Prior Mitigation Proposal did not transfer control over the capacity necessary to mitigate the screen failures identified in the Merger Order. According to Applicants, the Interim Mitigation Proposal addresses this issue in two ways. First, by identifying the purchasers and entering into contracts with them prior to filing their proposal, Applicants claim that they have addressed the Commission's concern that Applicants would have difficulty finding a purchaser.[89] Second, Applicants state that the "must take" feature of the Power Sales Agreements ensures that the energy will be purchased subject only to the occurrence of *force majeure* events and will be beyond their control. Applicants argue that their analysis demonstrates that the sales to Cargill, EDF Trading, and Morgan Stanley will resolve all of the screen failures, and that they have thus addressed the Commission's concern in the Compliance Order that Applicants assumed that two new market entrants would purchase the AEC Energy that they proposed to offer for sale.[90]

39. Applicants also assert that the interim mitigation proposal addresses other specific shortcomings of the Prior Mitigation Proposal that the Commission identified in the Compliance Order. First, Applicants state that the Compliance Order criticized the restrictions on eligible purchasers in the Prior Mitigation Proposal that required the sales to be used to serve load in the Duke Energy Carolinas and Progress Energy Carolinas-

[87] March 26 Compliance Filing at 20.

[88] March 26 Compliance Filing at 20.

[89] March 26 Compliance Filing at 21.

[90] March 26 Compliance Filing at 22.

East BAAs. Applicants state that the interim mitigation proposal contains no such restrictions.[91] Second, to address the uncertainty as to the availability of energy under the Prior Mitigation Proposal, Applicants state that under the Interim Mitigation Proposal "the energy will be made available in all hours in which it is required to be sold."[92] Third, in response to the lack of detail provided in the Prior Mitigation Proposal regarding the price of the energy to be sold, Applicants have fixed the price of capacity in the Power Sales Agreements and state that the price of energy is easily calculable based on the specified heat rate and the published natural gas price index.

40. Fourth, Applicants explain that, in response to the lack of detail in the Prior Mitigation Proposal regarding the provisions that would have allowed Applicants to interrupt deliveries, the Power Sales Agreements specify that any interruption of deliveries of energy by Duke Energy Carolinas or Progress Energy Carolinas will result in the payment of liquidated damages unless that interruption is excused on specified *force majeure* grounds. Fifth, Applicants state that although the Compliance Order found that Applicants did not justify the eight-year term of sales under the Prior Mitigation Proposal, the Interim Mitigation Proposal addresses this issue by providing that the interim sales will be made until the Transmission Expansion Projects are placed in service. Sixth, to address the finding in the Compliance Order that Applicants did not provide enough detail about the independent monitor, Applicants explain that they have executed a contract with Potomac Economics to be the Independent Monitor of the proposed sales and have included the agreement as an attachment to the March 26 Compliance Filing.[93] Finally, Applicants state that, by identifying the purchasers prior to filing the interim mitigation proposal, the Commission's concern in the Compliance Order that Applicants failed to provide for the sale of AEC Energy regardless of the price offered by purchasers has been mooted.

41. Applicants explain that they have structured the duration of the Power Sales Agreements so that extending them or entering into new Power Sales Agreements should be unnecessary. Applicants have "estimated that all of the transmission projects…can be completed within three years which is approximately June 1, 2015, the commencement of the Summer Period when mitigation is required under the Merger Order."[94] According to

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[91] March 26 Compliance Filing at 22.

[92] March 26 Compliance Filing at 22.

[93] *See* March 26 Compliance Filing, Exhibit D: Executed Contract with Potomac Economics to Perform Compliance Monitoring (Monitoring Agreement).

[94] March 26 Compliance Filing at 23.

Applicants, the Power Sales Agreements will extend through the last seasons/load periods where mitigation is necessary before the Transmission Expansion Projects are "projected to take effect."[95] Acknowledging the possibility that the transmission projects may not all be placed in service prior to June 1, 2015, Applicants state that they will either renew or enter into new Power Sales Agreements with alternate purchasers "on materially the same terms and conditions" if the Transmission Expansion Projects are not placed into service by that date.[96]

3. <u>Independent monitoring of Revised Mitigation Proposal</u>

42. Applicants explain that once the Proposed Transaction is completed, two aspects of the Revised Mitigation Proposal will be subject to monitoring by the Independent Monitor.[97] First, Potomac Economics will monitor whether the Power Sales Agreements remain in effect prior to the completion of the Transmission Expansion Projects and, if any of the agreements has been terminated or expires prior to completion of the Transmission Expansion Projects, Potomac Economics will monitor whether such agreement has been replaced with a new agreement under materially the same terms and conditions. Second, to the extent that the Commission requires Applicants to implement the Stub Mitigation, Potomac Economics will monitor Applicants' compliance with the transmission set-aside requirements. As noted above, Applicants include, as an attachment to the March 26 Compliance Filing, a copy of the executed contract with Potomac Economics.

4. <u>Applicants' response to April 2012 Information Request</u>

43. In the April 2012 Information Request, Applicants were directed to provide additional analyses and information. Specifically, Applicants were instructed to provide modified seasonal benchmark models for the 2011/2012 seasons that incorporated the Transmission Expansion Projects, and the Managing and Utilizing System Transmission (MUST) study results for those revised benchmark models. Applicants were further instructed to give a detailed narrative of any changes to the seasonal benchmark models other than the seven proposed Transmission Expansion Projects and the Greenville-Kinston Dupont 230 kV line. Applicants were instructed that if the SIL values resulting from the modified seasonal benchmark models differed from the SIL values provided in the March 26 Compliance Filing, Applicants should provide new DPT studies

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[95] March 26 Compliance Filing at 23.

[96] March 26 Compliance Filing at 24.

[97] March 26 Compliance Filing at 24.

incorporating those new values. Applicants were also required to answer questions regarding the impacts of the Transmission Expansion Projects on transmission capability from PJM to the Progress Energy Carolinas-East BAA.

44. On April 13, 2012, Applicants submitted the requested modified seasonal benchmark models and MUST studies. Applicants also provided modified DPT results based on the revised seasonal benchmark models (April 13 DPT) and responses to the questions regarding the impacts of the Transmission Expansion Projects on transmission capability from PJM Interconnection, L.L.C. (PJM) to the Progress Energy Carolinas-East BAA.

B. Comments and Protests

45. City of Orangeburg argues that the Revised Mitigation Proposal does not constitute "proper mitigation" because Applicants are not divesting themselves of control over their system generation resources pursuant to the Power Sales Agreements, and because the proposal provides for the "indefinite provision of interim mitigation measures" in violation of the Merger Policy Statement.[98] Additionally, City of Orangeburg challenges the mitigation allegedly provided by the Transmission Expansion Projects because the Commission "can have no assurance prior to the consummation of the merger that the Applicants will have secured all of the approvals necessary to construct the requisite upgrades."[99]

46. In its comments, City of Orangeburg also advances and reiterates several arguments related to certain state regulatory conditions that City of Orangeburg claims have interfered with and continue to interfere with the Commission's jurisdiction and both the Prior and Revised Mitigation Proposals.[100] According to City of Orangeburg,

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[98] City of Orangeburg Comments on Revised Mitigation Proposal at 2-3.

[99] City of Orangeburg Comments on Revised Mitigation Proposal at 4 (*citing* Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,121).

[100] Duke Energy and Progress Energy are both subject to certain existing state regulatory conditions that were imposed by the North Carolina Commission during previous mergers. Among other things, these conditions require the companies to provide notice to the North Carolina Commission before granting native load priority to new wholesale customers and to serve their Retail Native Load Customers in North Carolina with the lowest-cost power before making sales to customers that are not Retail Native Load Customers. In addition, the state reserves the right to assign, allocate and make *pro forma* adjustments with respect to the revenues and costs associated with wholesale contracts for retail ratemaking purposes. The companies have proposed

(continued...)

pursuant to the state regulatory conditions, the North Carolina Commission "claims authority to determine the customers to whom [Duke Energy Carolinas and Progress Energy Carolinas] can sell and provide firm wholesale power."[101] City of Orangeburg asserts that, because the North Carolina Commission has not granted the Power Sales Agreements customers native load status, Applicants have had to tailor the Power Sales Agreements to "not run afoul of the [North Carolina Commission's] determination that their respective retail load and [North Carolina Commission] designated wholesale 'native' load is entitled to service priority ahead of all other sales," including sales under the Power Sales Agreements.[102] Thus, according to City of Orangeburg, the Power Sales Agreements actually provide for transmission contingent sales of "interruptible surplus energy,"[103] not firm sales of energy. Reiterating arguments it has made in several previously filed pleadings,[104] City of Orangeburg argues that the North Carolina Commission's efforts to decide wholesale service rights is beyond that commission's jurisdiction and violates the Constitution and federal law.[105] City of Orangeburg notes that its request for declaratory relief regarding the state regulatory conditions remains pending before the Commission. City of Orangeburg also states, that in this proceeding, the Commission did not reach the substance of City of Orangeburg's arguments concerning the state regulatory conditions, holding that they are irrelevant to the Commission's evaluation of the Proposed Transaction, and that it has sought rehearing.[106]

47. Citing to the Merger Order, City of Orangeburg notes that the Commission rejected the Prior Mitigation Proposal because the proposed virtual divestiture did not transfer control of Applicants' generation. City of Orangeburg asserts that the same flaw exists with respect to the Interim Mitigation Proposal under the Revised Mitigation

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similar conditions for the Proposed Transaction at the state level. These conditions are referred to in this order as the state regulatory conditions.

[101] City of Orangeburg Comments on Revised Mitigation Proposal at 5.

[102] City of Orangeburg Comments on Revised Mitigation Proposal at 9.

[103] City of Orangeburg Comments on Revised Mitigation Proposal at 10.

[104] *See, e.g.* Motion to Intervene and Protest of the City of Orangeburg, South Carolina, Docket Nos. EC11-60-000, ER11-3306-000, ER11-3307-000 (not consolidated) (June 3, 2011).

[105] City of Orangeburg Comments on Revised Mitigation Proposal at 11-12.

[106] City of Orangeburg Comments on Revised Mitigation Proposal at 13-14.

Proposal. Although Applicants claim that the Power Sales Agreements entail firm sales of capacity and energy and describe the product as "'Capacity and Firm (LD) Energy, as defined in Schedule P of the EEI Master Agreement,"[107] according to City of Orangeburg, the Commission has found that the sale of the EEI Master Agreement Firm (LD) product "'gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity.'"[108] Thus, according to City of Orangeburg, a purchase and sale of Firm LD under the base EEI Master Power Purchase and Sales Agreement does not entail a sale of capacity, and is simply a sale of energy.

48. City of Orangeburg further argues that the Power Sales Agreements actually include transformative modifications that convert the product being sold into an interruptible, non-firm product. City of Orangeburg states that, under the *pro forma* EEI Master Agreement, the purchaser's right to receive energy and the seller's obligation to provide energy is limited only by *force majeure* as that term is defined in the EEI Master Agreement.[109] City of Orangeburg explains, however, that rather than using the *force majeure* clause established in section 1.23 of the EEI Master Agreement, Applicants have "materially rewritten" the Power Sales Agreements' *force majeure* clause to excuse the buyer's performance "'if... transmission is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Delivery Point to the Buyer's

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[107] City of Orangeburg Comments on Revised Mitigation Proposal at 17 (*quoting* March 26 Compliance Filing, Exhibit C: Executed Power Sales Agreements Provided as Interim Mitigation, Duke Energy Carolinas-Cargill Power Sales Agreement at 1 (Duke Energy Carolinas-Cargill Power Sales Agreement). The other Power Sales Agreements include identical language.

[108] City of Orangeburg Comments on Revised Mitigation Proposal at 17 (*quoting* *Integrys Energy Grp., Inc.*, 123 FERC ¶ 61,034, at P 11 (2008)).

[109] City of Orangeburg Comments on Revised Mitigation Proposal at 18. City of Orangeburg states that section 1.23 of the EEI Master Agreement defines "Force Majeure," in relevant part, as follows:

> an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstances was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided.

City of Orangeburg Comments on Revised Mitigation Proposal at 18.

proposed ultimate sink, regardless of whether transmission, if any, that Buyer is attempting to secure and/or has purchased for the Product is firm or non-firm.'"[110] As a consequence of these changes, City of Orangeburg asserts that Applicants have "fundamentally changed the nature of the product sold" into Transmission Contingent energy.[111] According to City of Orangeburg, the Commission has never held that the sale of transmission contingent energy entails a transfer of control over merging entities' generating resources and thus constitutes an acceptable form of mitigation. In addition, City of Orangeburg likens the virtual divestiture proposed in *Allegheny Energy, Inc.*, 84 FERC ¶ 61,223 (1998) (*Allegheny Energy*), which the Commission rejected because the lack of assured transmission service decreased the certainty that the output at issue would be sold, with the Power Sales Agreements, where no energy will be sold if buyers cannot secure transmission to the destination markets.[112]

49. City of Orangeburg also argues that buyers under the Power Sales Agreements will face the constant risk of product unavailability because Applicants may need their system resources to serve retail and wholesale native load. City of Orangeburg asserts that, to mitigate this uncertainty, the buyers may elect to market the energy purchased under the Power Sales Agreements on a day-ahead or real-time basis. City of

[110] City of Orangeburg Comments on Revised Mitigation Proposal at 19 (*quoting* March 26 Compliance Filing, Exhibit C, Duke Energy Carolinas-Cargill Power Sales Agreement at 5).

[111] City of Orangeburg Comments on Revised Mitigation Proposal at 19. Transmission Contingent energy is defined in Schedule P of the EEI Master Agreement as follows:

> "Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable…if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm.

City of Orangeburg Comments on Revised Mitigation Proposal at 20 (*quoting* definition of a Transmission Contingent product under Schedule P of the EEI Master Agreement).

[112] City or Orangeburg Comments on Revised Mitigation Proposal at 21.

Orangeburg claims, however, that because the Power Sales Agreements will be operative during the winter and summer peak season, "there is every reason to believe" that the buyers "will in fact find themselves unable to secure transmission, or will have transmission curtailed or interrupted at times."[113] City of Orangeburg not only concludes that Applicants will retain complete control over their system resources, but that there are substantial opportunities for the buyers to avoid taking or paying for energy by simply identifying an ultimate sink where transmission service is unavailable. According to City of Orangeburg, Applicants fail to acknowledge or address the transmission contingent nature of the Power Sales Agreements,[114] and fail to show that the interim mitigation measures will transfer control of Applicants' generation and cure screen failures identified in the Merger Order.[115] City of Orangeburg also claims that Applicants have provided "no explanation" for the negative capacity prices in the Power Sales Agreements. City of Orangeburg asserts that having to pay buyers to take the transmission contingent surplus energy sold pursuant to the Power Sales Agreements "belies Applicants' claim of having engaged in a meaningful divestiture of system resources."[116]

50. City of Orangeburg also challenges Applicants' claims regarding the proposed Transmission Expansion Projects. According to City of Orangeburg, based on statements by Applicants to the North Carolina Commission, it is "unclear whether or when [the Transmission Expansion Projects] will ever be completed"[117] because Applicants have stated that implementation of the Revised Mitigation Proposal "depends on the resolution of acceptable state retail ratemaking treatment of the proposed transmission upgrades."[118] City of Orangeburg further asserts that Applicants fail to mention this contingency in the March 26 Compliance Filing, and, in fact, suggest that there are no impediments to Applicants constructing the Transmission Expansion Projects. City of Orangeburg emphasizes that Applicants do not "guarantee to construct the proposed transmission

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[113] City of Orangeburg Comments on Revised Mitigation Proposal at 22.

[114] City of Orangeburg Comments on Revised Mitigation Proposal at 23.

[115] City of Orangeburg Comments on Revised Mitigation Proposal at 25.

[116] City of Orangeburg Comments on Revised Mitigation Proposal at 25.

[117] City of Orangeburg Comments on Revised Mitigation Proposal at 26.

[118] City of Orangeburg Comments on Revised Mitigation Proposal at 26 (*citing Duke Energy Carolinas, LLC's Advance Notice of Filing of Proposed Mitigation Plan at the Federal Energy Regulatory Commission*, Docket No. E-7, Sub 995 (Feb. 22, 2012)).

upgrades and to do so by a set date."[119] This omission, City of Orangeburg argues, is unsurprising given Applicants' representations to the North Carolina Commission.

51. According to City of Orangeburg, Applicants are seeking Commission approval for the merger based on an alleged permanent solution that may never be completed or implemented, or which may be "materially altered" to satisfy the concerns of the North Carolina Commission.[120] City of Orangeburg expresses concern that the Commission has not received a commitment from Applicants that the Transmission Expansion Projects will be in service by a date certain and that, post-merger, the Commission "would have seemingly little ability to ensure the construction of the upgrades."[121] Based on these concerns, City of Orangeburg asserts that even assuming that the Power Sales Agreements are an adequate form of interim mitigation, Applicants' proposed renewal of the agreements and proposal to enter into similar replacement agreements do not "constitute a proper substitute for the proposed permanent solution of transmission upgrades."[122]

52. Finally, City of Orangeburg argues that the failings of the Revised Mitigation Proposal could be rectified if the Commission declared the state regulatory conditions illegal. City of Orangeburg asserts that although Applicants could sell capacity and energy in such a way as to virtually divest themselves of control over the requisite level of system resources necessary to cure the screen failures in the interim period, Applicants will not do so until they are "reasonably certain" that they will not be punished by the North Carolina Commission for entering into such sales.[123] City of Orangeburg urges the Commission to find that the North Carolina Commission lacks the authority to determine what Duke Energy Carolinas' and Progress Energy Carolinas' wholesale customers are native load customers "entitled to be served from their system resources on a basis equivalent to retail load."[124] City of Orangeburg states that the Commission should "exercise its authority under PURPA [the Public Utility Regulatory Policies Act] to supersede directly the [state regulatory conditions] and permit lawful coordination to

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[119] City of Orangeburg Comments on Revised Mitigation Proposal at 28.

[120] City of Orangeburg Comments on Revised Mitigation Proposal at 29-30.

[121] City of Orangeburg Comments on Revised Mitigation Proposal at 30.

[122] City of Orangeburg Comments on Revised Mitigation Proposal at 29.

[123] City of Orangeburg Comments on Revised Mitigation Proposal at 32.

[124] City of Orangeburg Comments on Revised Mitigation Proposal at 32.

effectuate the merger, the [Joint Dispatch Agreement], and any interim and permanent mitigation necessary to mitigate the screen failures, including the proposed transmission upgrades."[125]

53. According to City of New Bern, the four Power Sales Agreements "do not actually remove operational control of the generation that is supposed to be the subject of the [Power Sales Agreements]" from Applicants.[126] Like City of Orangeburg, City of New Bern notes that the four Power Sales Agreements involve net capacity payments to the buyers and that Applicants have customized the *force majeure* clause of the EEI Master Agreement to excuse non-performance if transmission beyond the delivery point is unavailable for "any reason."[127] City of New Bern argues that by altering the *force majeure* clause, Applicants have "engrafted" the definition of the term "Transmission Contingent" from Schedule P of the EEI Master Power Purchase and Sale Agreement onto the *force majeure* provision of the Power Sales Agreements.[128] According to City of New Bern, this change effectively "renders a nominally 'firm' transaction contingent on one or both of the Buyer's willingness to arrange, or the Seller's willingness to make available, transmission service."[129] City of New Bern asserts that this result is logical when viewed in conjunction with Applicants' statements to the North Carolina Commission. According to City of New Bern, Applicants have assured the North Carolina Commission that all retail and wholesale native load obligations will be served prior to any offers of energy made pursuant to the Power Sales Agreements, and that service to retail native load customers will not be impacted.[130]

54. City of New Bern also takes issue with the fact that the Power Sales Agreements do not prevent Applicants from buying back power from Cargill, Morgan Stanley, and EDF Trading. In this regard, City of New Bern asserts that the Commission has used "a substantial buy-back penalty or premium" in other merger proceedings involving

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[125] City of Orangeburg Comments on Revised Mitigation Proposal at 32.

[126] City of New Bern Protest of Revised Mitigation Proposal at 3.

[127] City of New Bern Protest of Revised Mitigation Proposal at 6.

[128] City of New Bern Protest of Revised Mitigation Proposal at 6.

[129] City of New Bern Protest of Revised Mitigation Proposal at 7.

[130] City of New Bern Protest of Revised Mitigation Proposal at 8 (*citing* March 26, 2012 Letter from Applicants to North Carolina Commission accompanying Revised Mitigation Proposal, NCUC Docket Nos. E-2, Sub 998 and E-7, Sub 986).

temporary divestitures to prevent merger applicants from undermining the effectiveness of mitigation proposals.[131] City of New Bern concludes that these terms of the Power Sales Agreements "are entirely inconsistent with the relinquishment of operational control" that the Commission requires before accepting a virtual divestiture proposal.[132]

55. In addition to the alleged flaws of the Power Sales Agreements, City of New Bern claims that Applicants may fail to complete the proposed transmission upgrades in which case their "woefully ineffective" interim mitigation proposal could become permanent.[133] City of New Bern agrees with City of Orangeburg that construction of the proposed transmission upgrades is contingent upon the "acceptable resolution" of "rate base treatment" by the North Carolina Commission,[134] and contends that the North Carolina Commission might not decide this issue until after the Commission has acted in this proceeding. City of New Bern asserts that the uncertainty surrounding this issue is an "unstated contingency" that undercuts Applicants' claim about the effectiveness or the proposed transmission upgrades.[135]

56. City of New Bern also challenges Applicants' proposed permanent mitigation. City of New Bern alleges that two of the proposed transmission upgrade projects – the Antioch transformer upgrade and the third Lilesville-Rockingham 230 kV Line – are "foreseeable and reasonably certain" to be constructed absent the merger and, therefore, ineligible for consideration as proposed mitigation.[136] According to City of New Bern, Applicants included these two upgrades in previous transmission plans that they "participated in developing."[137] City of New Bern contends that excluding these two projects from being considered as mitigation reduces Applicants' claimed SIL increase, and that a recalculation of market concentration levels shows "significant and severe

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[131] City of New Bern Protest of Revised Mitigation Proposal at 8 (*citing American Electric Power*, 90 FERC ¶ 61,242 (2000)).

[132] City of New Bern Protest of Revised Mitigation Proposal at 9.

[133] City of New Bern Protest of Revised Mitigation Proposal at 10.

[134] City of New Bern Protest of Revised Mitigation Proposal at 11-12.

[135] City of New Bern Protest of Revised Mitigation Proposal at 12.

[136] City of New Bern Protest of Revised Mitigation Proposal at 13 (*citing OG&E-NRG McClain I*, 105 FERC ¶ 61,297, at P 32 (2003)).

[137] City of New Bern Protest of Revised Mitigation Proposal at 13.

exceedance[s]" of the relevant market concentration thresholds.[138] Specifically, City of New Bern asserts that the HHI levels for the Duke Energy Carolinas BAA increase by 121 points in the Summer Off-Peak season/load period and 175 points in the Winter Off-Peak season/load periods; both of these seasons/load periods are highly concentrated. With respect to the Progress Energy Carolinas-East BAA, City of New Bern claims that the HHI increases by 189 points in the moderately concentrated Summer Off-Peak period. Based on this analysis, City of New Bern concludes that the proposed transmission upgrades do not provide acceptable mitigation.

57. Finally, City of New Bern argues that Applicants' inclusion of the Stub Mitigation confirms its earlier observation that Applicants should treat this interface as internal to the merged company for purposes of analyzing market concentration.[139] City of New Bern reiterates that Applicants should have treated the interface as internal to the merged company because Applicants would otherwise be unable to operate pursuant to the Joint Dispatch Agreement proposed in Docket No. ER12-1338-000 without asserting and using the native load priority identified in the Commission's regulations.[140] City of New Bern concludes that Applicants' market concentration calculations are "fundamentally flawed" and that recalculation of these values with the correct treatment of the interface results in "pervasive and severe screen failures."[141]

58. FMPA protests the Revised Mitigation Proposal, arguing that it fails to ameliorate concerns about market power in peninsular Florida. FMPA takes issue with the Commission's conditional approval of the Proposed Transaction without investigating or taking action "to alleviate Florida market power," and states that it has filed for rehearing of the Commission's decision not to address this issue in the Merger Order.[142] According to FMPA, whether the Commission finds that the Revised Mitigation Proposal is consistent with the public interest as to Florida depends on the Commission's ruling on FMPA's pending rehearing request. Reiterating the arguments made in that pleading,[143]

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[138] City of New Bern Protest of Revised Mitigation Proposal at 14.

[139] City of New Bern Protest of Revised Mitigation Proposal at 15.

[140] City of New Bern Protest of Revised Mitigation Proposal at 16 (*citing* 18 C.F.R. § 33.3(c)(4)(i)(D)).

[141] City of New Bern Protest of Revised Mitigation Proposal at 17.

[142] FMPA Protest of Revised Mitigation Proposal at 2.

[143] FMPA claims, for example, that it has shown in its rehearing request that Florida Power Corporation, a subsidiary of Progress Energy, has "substantial

(continued…)

FMPA asserts that, despite the concerns it has raised the Commission has failed to make a "meaningful investigation" of potential merger impacts on Florida market power.[144] Because of the Commission's alleged failure to properly investigate these issues, FMPA asserts that Applicants have ignored transmission improvements into or within Florida and therefore the Revised Mitigation Proposal fails.[145] Consequently, FMPA asks the Commission to reject the Revised Mitigation Proposal and order "hearings and discovery and other appropriate procedures" to address the Florida market power issues.[146] FMPA also asks the Commission to order Applicants to mitigate their Florida market power by expanding the Florida interface, offering "other Florida transmission relief" and requiring "corrective base load and other power supply relief for Florida."[147]

59. EPSA argues that the Commission should reject the Revised Mitigation Proposal because it is an insufficient remedy to the Commission's market power concerns. EPSA contends that requiring Applicants to join an RTO appears to be the "easiest and least cost solution" to address the Commission's concerns,[148] and suggests that an ICT arrangement could also alleviate market power if structured and implemented properly.[149] Noting that many of the details relating to the viability and efficacy of the proposed permanent mitigation are based on non-public information, EPSA states that construction of the proposed transmission upgrades depends upon the resolution of various issues at the state level. Like City of New Bern, EPSA points out that resolution of these issues will not occur until after the Commission has acted upon the Revised Mitigation Proposal, and that such state actions may involve further conditioning that could render construction of the proposed transmission upgrades "unpalatable" to Applicants.[150]

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entitlements" to Florida-Georgia interface capacity from which the merged company will benefit, and that the merged company will have "increased dominance in nuclear and other baseload power." FMPA Protest of Revised Mitigation Proposal at 3.

[144] FMPA Protest of Revised Mitigation Proposal at 3.

[145] FMPA Protest of Revised Mitigation Proposal at 3.

[146] FMPA Protest of Revised Mitigation Proposal at 4.

[147] FMPA Protest of Revised Mitigation Proposal at 4.

[148] EPSA Comments on Revised Mitigation Proposal at 3.

[149] EPSA Comments on Revised Mitigation Proposal at 2.

[150] EPSA Comments on Revised Mitigation Proposal at 4.

60. In addition to the uncertainty surrounding these state level decisions, EPSA asserts that Applicants' proposal to construct the proposed transmission upgrades appears "fraught with the potential for delay."[151] EPSA notes, for example, that the proposal appears to have compressed a long-term transmission planning proposal into a three-year window.[152] In addition, EPSA contends that, among other things, obtaining materials, equipment, and construction crews, conducting training, weather delays, and local permit requirements could delay the construction of the proposed transmission upgrades.[153] EPSA also points out that several of the proposed transmission upgrades depend upon the acceleration of the Greenville-Kinston Dupont 230 kV line, and the cooperation of American Electric Power and Dominion Virginia Power. According to EPSA, these contingencies create further potential for delay.[154] EPSA echoes City of Orangeburg's concern that the Revised Mitigation Proposal does not include a commitment to complete the proposed transmission upgrades by a date certain, and that Applicants have structured the terms of the Interim Mitigation Proposal so that it may continue indefinitely.[155] EPSA concludes that, in contrast to joining an RTO, the proposed transmission upgrades solution does not address the Commission's concerns and resolve Applicants' market power with "the certainty necessary to justify approval" of the Revised Mitigation Proposal.[156]

61. In his April 16, 2012 comments, Mr. McManus argues that the Commission should not accelerate its review of the Revised Mitigation Proposal because that date will not negatively impact Applicants, their stakeholders, or their wholesale and retail customers.[157] Mr. McManus also argues that Applicants have not provided firm commitments to complete the Transmission Expansion Projects; that the negative capacity payments in the Power Sales Agreements are contrary to Commission precedent

[151] EPSA Comments on Revised Mitigation Proposal at 5.

[152] EPSA Comments on Revised Mitigation Proposal at 4-5.

[153] EPSA Comments on Revised Mitigation Proposal at 5.

[154] EPSA Comments on Revised Mitigation Proposal at 6.

[155] EPSA Comments on Revised Mitigation Proposal at 5-6.

[156] EPSA Comments on Revised Mitigation Proposal at 8.

[157] Comments Regarding Revised Mitigation Proposal as Submitted by Duke Energy Corporation and Progress Energy, Inc. on March 26, 2012 at 3, 8, Docket No. EC11-60-000 (Apr. 16, 2012) (McManus April 16 Comments).

and will result in cost shifts; and that the Revised Mitigation Proposal may negatively impact retail native load customers.[158] In his April 30, 2012 comments, Mr. McManus claims that Applicants should be required to submit the Transmission Expansion Projects for review and approval by the North Carolina Transmission Planning Collaborative, and that Applicants should resubmit the Revised Mitigation Proposal and provide a guarantee that there will be no increase in costs over those associated with the Prior Mitigation Proposal.[159] Finally, Mr. McManus asserts that, when considering Applicants' merger commitments and obligations, the Commission should review and consider the post-merger efforts by Carolina Power & Light and Florida Power Corporation to fulfill the commitments and obligations those companies offered to resolve issues related to a prior merger.[160]

C. Applicants' answer to protests of the Revised Mitigation Proposal and responsive pleadings

62. In their answer, Applicants note that "no party with load in the [Duke Energy Carolinas] or [Progress Energy Carolinas-East] BAAs that actually is in the market to purchase or sell at wholesale" has protested the Revised Mitigation Proposal.[161] Applicants also address the various arguments raised by protestors asserting that uncertainty exists regarding the Transmission Expansion Projects. Specifically, Applicants state that, once the merger closes, they will be "absolutely and unequivocally committed to fulfilling *all* of the commitments they have made, including the commitment to construct the transmission projects that implement permanent mitigation."[162] In response to concerns that the construction of these projects depends upon obtaining favorable retail ratemaking treatment from the North Carolina

[158] Comments Regarding Revised Mitigation Proposal as Submitted by Duke Energy Corporation and Progress Energy, Inc. on March 26, 2012 at 8, Docket No. EC11-60-000 (Apr. 16, 2012) (McManus April 16 Comments).

[159] Comments Regarding Revised Mitigation Proposal as Submitted by Duke Energy Corporation and Progress Energy, Inc. on March 26, 2012 at 5, Docket No. EC11-60-000 (Apr. 30, 2012)

[160] Comments Regarding Revised Mitigation Proposal as Submitted by Duke Energy Corporation and Progress Energy, Inc. on March 26, 2012 at 3, Docket No. EC11-60-000 (May 7, 2012)

[161] Applicants May 1 Answer at 2.

[162] Applicants May 1 Answer at 3-4 (emphasis in original).

Commission, Applicants state that they will resolve this issue before the merger's closing.[163] Applicants state that resolution of that issue will not affect their commitment to construct the transmission upgrades once the merger closes.[164] Applicants state:

> The need to reach agreement on the retail rate treatment for the transmission projects will be satisfied before the [Proposed Transaction] closes. The Applicants' commitment to construct the transmission projects after the [Proposed Transaction] closes is completely unaffected by this need. Although the Applicants do not believe it to be necessary, they reaffirm here their commitment to construct the transmission expansion projects identified in their Mitigation Proposal after the [Proposed Transaction] closes.[165]

63. With regard to arguments about the completion date of the Transmission Expansion Projects, Applicants state that such projects "[b]y their very nature" are subject to circumstances and events outside of the project sponsor's control,[166] however, Applicants maintain that they anticipate no material delay to keep the transmission upgrades from going into service by the summer of 2015. Applicants also reiterate their commitment to keep interim mitigation in place until the transmission upgrades are complete, which Applicants claim provides "a substantial economic incentive" to finish the projects' construction on a timely basis.[167]

64. In addition to these assurances, Applicants commit to work "diligently towards completing the projects within the scope and time frame" laid out in the Revised Mitigation Proposal.[168] Applicants also express their willingness to expand the Independent Monitor's scope of work to include monitoring the extent to which Applicants "are pursuing the construction of the proposed projects within the scope and

[163] Applicants May 1 Answer at 3, 8.

[164] Applicants May 1 Answer at 8.

[165] Applicants May 1 Answer at 8.

[166] Applicants May 1 Answer at 10.

[167] Applicants May 1 Answer at 11.

[168] Applicants May 1 Answer at 11.

time frame identified" and "reporting to the Commission when the projects have been completed and placed in service."[169]

65. On the issue of whether a transmission project can constitute "acceptable mitigation," Applicants explain that a project may do so if the project sponsor does not expect to place the project in service absent the merger. In contrast, a proposed transmission project should only "be included in the pre-merger analysis . . . if it is foreseeable and reasonably certain to be completed."[170] Applicants also point out that the Commission does not require merger applicants to include projects that the merging parties expect to construct "well beyond the time frame" of the DPT analysis.[171] Based upon these clarifications, Applicants dispute City of New Bern's allegations that certain of the transmission upgrades should not be considered valid mitigation by the Commission. While Applicants admit that the 2007, 2008, and 2009 annual North Carolina Transmission Planning Collaborative (NCTPC) transmission study reports describe the Antioch upgrade and the Lilesville-Rockingham 230 kV Line as "Planned" or "Underway,"[172] Applicants state that they commenced neither project and took both out of their plans. Applicants also note that none of the proposed transmission upgrades are included in the current NCTPC annual study report or in Duke Energy Carolinas' or Progress Energy Carolinas' internal transmission plans. Finally, Applicants observe that City of New Bern's testimony actually demonstrates that none of Applicants' proposed transmission upgrades would be placed in service in the next ten years, absent the merger.

66. Applicants also dispute City of New Bern's argument that Applicants should treat the interface between Duke Energy Carolinas and Progress Energy Carolinas as internal to the merged company. They argue that the purpose of the Stub Mitigation is to ensure that Applicants are unable to reserve import capacity on that external interface on a firm basis and that it is irrelevant to the question of whether to treat the interface as external or internal.[173]

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[169] Applicants May 1 Answer at 11.

[170] Applicants May 1 Answer at 13.

[171] Applicants May 1 Answer at 14.

[172] Applicants May 1 Answer at 14.

[173] Applicants May 1 Answer at 16.

67. Applicants also respond to the claims advanced by protestors regarding the *force majeure* clause in the Power Sales Agreements. Applicants state that the inclusion in the Power Sales Agreements of a modified version of the standard *force majeure* clause in the EEI Master Agreement is beneficial to the buyers and that the buyers consider the Power Sales Agreement sales to be "firm sales."[174] More specifically, Applicants explain that the *force majeure* clause only excuses the buyers' obligations to perform, and, even then, only under limited circumstances. Applicants state that this modification does not affect their obligation, as sellers, to deliver energy regardless of transmission constraints.[175] Additionally, Applicants contend that even if a buyer is unable to secure transmission from the delivery point to its proposed sink, it can choose to take delivery of the energy at the delivery point to sell to customers in the Duke Energy Carolinas or Progress Energy Carolinas-East BAAs or to customers located outside of the BAAs. Thus, the ability to invoke the *force majeure* clause is, according to Applicants, "entirely up to the buyers."[176] Furthermore, despite protestor allegations that sales pursuant to the Power Sales Agreement depend upon the sellers' willingness to make transmission capacity available, Applicants state that they have no discretion in this regard, as their Open Access Transmission Tariff (OATT) and the Commission's regulations require them to offer all available transmission capacity to third parties.[177] Moreover, Applicants state that in instances where Applicants could make a sale after a buyer exercises its *force majeure* rights, such sales would represent "increased sales" into the market that would "have the same pro-competitive effect as the sales Applicants make to the power marketers under the" Power Sales Agreements.[178]

68. In reply to protestor concerns regarding the negative capacity prices in the Power Sales Agreements, Applicants observe that the Compliance Order required Applicants "to

[174] Applicants May 1 Answer at 19. In its answer, Applicants included letters from Cargill and Morgan Stanley that express these buyers' support for this modification.

[175] Applicants May 1 Answer at 20-21.

[176] Applicants May 1 Answer at 22.

[177] Applicants disagree with City of Orangeburg's claim that Applicants will be able to interrupt deliveries under the Power Sales Agreements. Rather, they argue that they must be able to deliver energy every hour as required by the agreements to avoid the risk of paying "substantial damages." Applicants May 1 Answer at 25.

[178] Applicants May 1 Answer at 23.

sell all of the energy that is offered, regardless of the price of the bids."[179] Applicants explain that pursuant to the Power Sales Agreements, the buyers will have the absolute right to take capacity on a 24/7 basis absent a *force majeure* event. Applicants also state that the negative capacity payments constitute sunk costs that do not create an incentive for the buyers to invoke *force majeure* and that are "completely irrelevant" to the interim mitigation's effectiveness.[180]

69. Applicants also respond to concerns regarding their ability to repurchase the energy sold pursuant to the Power Sales Agreements. Applicants argue that City of New Bern has cited no Commission precedent to support its assertion that the Commission prohibits this practice, and that City of New Bern has misconstrued the precedent it relies on. Applicants also state that the Commission has never prohibited sales of energy back to merger applicants. Applicants explain that if buyers choose to sell the energy back to Applicants, they would do so at market prices that would "likely be different from the price under the [Power Sales Agreements]."[181] Applicants contend that any energy that they buy back "is not being withheld from the market but instead is being delivered into the market – a procompetitive result that is no different in effect than if the power marketers had sold the energy to a third party instead of to the Applicants."[182]

70. Finally, Applicants ask the Commission to reject City of Orangeburg's request that the Commission consolidate the merger proceeding in Docket No. EC11-60-000 with the Power Sales Agreements proceedings in Docket Nos. ER12-1339-000, ER12-1340-000, ER12-1341-000, and ER12-1342-000. Applicants reason that the merger proceeding and the Power Sales Agreements should be evaluated pursuant to the standards of FPA sections 203 and 205, respectively, and therefore should not be consolidated.[183]

71. In its answer, City of Orangeburg reiterates its earlier claim that the Power Sales Agreements do not constitute proper mitigation to cure the identified screen failures, asserting that the buyers will be able to utilize the modified *force majeure* provisions to

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[179] Applicants May 1 Answer at 24 (citing Compliance Order, 137 FERC ¶ 61,210 at P 81, n.147).

[180] Applicants May 1 Answer

[181] Applicants May 1 Answer at 27.

[182] Applicants May 1 Answer at 27.

[183] Applicants May 1 Answer at 28.

"game" the Power Sales Agreements and avoid taking the quantities of energy specified in the agreements.[184] City of Orangeburg also states that the HHI calculations that Applicants included with the March 26 Compliance Filing rely upon the "foundational assumption" that Applicants will sell the full amount of energy specified in the Power Sales Agreements "during every clock hour of the respective contract periods."[185] Hence, City of Orangeburg concludes that the HHI calculations rely upon a "faulty understanding" of the Power Sales Agreements.[186] City of Orangeburg also reasons that Applicants' interim mitigation proposal is inadequate to address the Commission's horizontal competition concerns because Applicants will maintain control over their system resources whenever the buyers "refuse" to take the offered energy due to transmission unavailability.[187]

72. City of Orangeburg also reiterates its claims that Applicants might not construct the Transmission Expansion Projects within the next ten years, as the North Carolina Commission could condition its approval of retail rate recovery for the proposed upgrades until they are necessary for "non-merger related system purposes."[188] Finally, City of Orangeburg argues, once again, that the scope of the mitigation is "constrained" by the state regulatory conditions. As support for its claim, City of Orangeburg points to the fact that Applicants May 1 Answer does not take issue with City of Orangeburg's allegations in this regard.[189] For this reason, City of Orangeburg reiterates its request that the Commission declare the State Regulatory Conditions to be illegal.[190]

73. North Carolina Commission Staff filed a response to City of Orangeburg's answer. In its answer, North Carolina Commission Staff takes no position "as to any aspect of the Revised Mitigation Proposal, including the nature of the service in the [Power Sales Agreements] and the degree of certainty as to whether the proposed transmission projects will be completed."[191] North Carolina Commission Staff argues, however, that the

[184] City of Orangeburg May 4 Answer at 4.

[185] City of Orangeburg May 4 Answer at 6.

[186] City of Orangeburg May 4 Answer at 7.

[187] City of Orangeburg May 4 Answer at 11-15.

[188] City of Orangeburg May 4 Answer at 15.

[189] City of Orangeburg May 4 Answer at 17.

[190] City of Orangeburg May 4 Answer at 18.

[191] North Carolina Commission Staff May 7 Answer at 2.

Commission should reject City of Orangeburg's comments and answer because they do not demonstrate a nexus been the Proposed Transaction and City of Orangeburg's alleged harms. According to North Carolina Commission Staff, City of Orangeburg's pleadings concede that City of Orangeburg is focused on existing state regulatory conditions, which will "continue in effect regardless of whether Applicants' proposed merger is consummated."[192] North Carolina Commission Staff states that these state policies will remain unresolved regardless of whether Applicants elect to terminate their proposed merger and that the Commission made such a determination in the Merger Order.[193] For these reasons, North Carolina Commission Staff asserts that the Commission should not allow City of Orangeburg to renew the same arguments in this proceeding.

74. North Carolina Commission Staff also argues that the State Regulatory Conditions are lawful, as the North Carolina Commission has done nothing to dictate or limit the type of energy or capacity that Duke Energy Carolinas, Progress Energy Carolinas, or Applicants may include in a wholesale non-native load sales contract.[194] North Carolina Commission Staff further argues that the North Carolina Commission's policies "simply require franchised public utilities in North Carolina to comply with their fundamental obligation to provide safe, reliable, and adequate service to their captive retail native load customers" and that the North Carolina Commission clearly has jurisdiction to do so.[195]

75. Finally, in response to City of Orangeburg's statements regarding the uncertain nature of the proposed Transmission Expansion Projects, North Carolina Commission Staff states that the North Carolina Commission is the entity designated to authorize the siting and construction of transmission facilities in North Carolina, and that in exercising such authority, the North Carolina Commission has full authority to "to ensure that all facilities are needed by retail customers and their costs are just and reasonable."[196] For these reasons, North Carolina Commission Staff asks the Commission to reject City of Orangeburg's suggestions that "there is something unlawful or improper about the

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[192] North Carolina Commission Staff May 7 Answer at 4.

[193] North Carolina Commission Staff May 7 Answer at 5-6 (*citing* Merger Order, 136 FERC ¶ 61,245 at P 147).

[194] North Carolina Commission Staff May 7 Answer at 11.

[195] North Carolina Commission Staff May 7 Answer at 12.

[196] North Carolina Commission Staff May 7 Answer at 15.

[North Carolina Commission] reviewing the transmission projects in the Revised Mitigation Proposal."[197]

76. In Applicants May 9 Supplement, Applicants state that since they filed their May 1 answer, they have reached a settlement with the North Carolina Commission Staff regarding retail rate recovery for the Transmission Expansion Projects. They also point out that EDF Trading has submitted a letter stating that: (1) the modified *force majeure* provision benefits EDF Trading; and (2) that it considers the sales pursuant to Power Sales Agreements to be "firm" sales of energy and capacity.[198]

77. Applicants also argue that City of Orangeburg's assertion that Power Sales Agreement buyers will only take as much energy as they wish demonstrates how the Power Sales Agreements provide effective mitigation. In support of this argument, Applicants state that because the buyers have a firm right to energy under the Power Sales Agreements, Applicants have no control over that capacity to withhold it from the market to raise energy prices. Applicants argue that the ability to withhold capacity from the market to raise energy prices is the hallmark of horizontal market power.[199] Applicants also state that because they cannot withhold this capacity, their DPT analysis rightly attributes this capacity to the buyers because "it is appropriate to attribute capacity in all hours to the entity that controls that capacity, even if the entity may not make sales in all hours."[200]

78. Finally, Applicants state that City of Orangeburg's insistence upon attacking the state regulatory conditions in every pleading undercuts the credibility of City of Orangeburg's other arguments. In this regard, Applicants point out that the Commission has already determined that the alleged harms associated with the State Regulatory Conditions "do not stem from the Proposed Transaction" and that City of Orangeburg is not located in the geographic markets where the Commission identified market power concerns.[201]

79. In response to Applicants May 9 Supplement, City of Orangeburg reasserts that Applicants will have full control over the operation of their system resources in all hours

[197] North Carolina Commission Staff May 7 Answer at 15.

[198] Applicants May 9 Supplement at 2-3.

[199] Applicants May 9 Supplement at 3.

[200] Applicants May 9 Supplement at 4-5.

[201] Applicants May 9 Supplement at 5.

where the buyers fail to purchase the full amount of energy pursuant to the Power Sales Agreements.[202] City of Orangeburg also reiterates its request for the Commission to find the State Regulatory Conditions illegal.[203]

80. City of New Bern filed a motion to strike in response to Applicants May 1 Answer and Applicants May 9 Supplement. City of New Bern moves to strike the April 30, 2012 letter from Cargill and the May 1, 2012 letter from Morgan Stanley, which were attached as exhibits to Applicants May 1 Answer. City of New Bern also moves to strike the May 1, 2012 letter from EDF Trading and the May 8, 2012 joint press release, which were attached as exhibits to Applicants May 9 Supplement. According to City of New Bern, the letters contain "unverified statements by non-parties, made outside of this proceeding,"[204] and provide no basis for concluding that the signatories have personal knowledge of the negotiations of the Power Sales Agreements or the qualifications required to provide expert opinions on the agreements. City of New Bern contends that the press release is not admissible because it is not proof of anything other than Applicants' issuance of a press release.

D. Analysis of Revised Mitigation Proposal

81. As discussed in further detail below, the Commission accepts the Revised Mitigation Proposal, subject to certain revisions and conditions. In the Compliance Order, the Commission stated that "an acceptable mitigation proposal must remedy the screen failures identified in the Merger Order, and provide a [DPT] analysis supporting the new HHI values."[205] We find that the Revised Mitigation Proposal, as supplemented by Applicants April 13 Information Request Answer and Applicants May 1 Answer, and as revised below, meets these requirements.

82. In accepting the Revised Mitigation Proposal, the Commission notes that it has stated that "an up front, enforceable commitment to upgrade or expand transmission facilities [may] mitigate market power, because the constraint relieved by such an upgrade or expansion no longer would limit the scope of the relevant geographic market."[206] As the Commission has explained: "[the] long-term remedy of expanding

[202] City of Orangeburg May 11 Answer at 2-6.

[203] City of Orangeburg May 11 Answer at 9.

[204] City of New Bern Motion to Strike at 3.

[205] Compliance Order, 137 FERC ¶ 61,210 at P 91.

[206] Merger Policy Statement, FERC Stats. & Regs ¶ 31,044 at 30,121.

transmission is one that the Commission has said can be an acceptable remedy to competitive harm."[207] In the March 26 Compliance Filing, Applicants commit to build seven proposed Transmission Expansion Projects. According to Applicants, three of the seven proposed Transmission Expansion Projects require the cooperation of American Electric Power and Dominion Virginia Power.[208] Applicants state that they have "discussed these projects with those two companies, and both have entered into memoranda of understanding under which these companies have agreed to negotiate binding agreements to undertake the projects."[209] According to Applicants, they "expect to negotiate and complete binding agreements with those companies during the pendency of the Commission's review period to ensure the completion of these projects."[210] In addition, Applicants explain that in order for four of the seven proposed Transmission Expansion Projects "to increase the SIL of the [Progress Energy Carolinas-East BAA] in the manner described" by Applicants' witness, the Greenville-Kinston Dupont 230kV Line must be in service by 2015.[211]

83. Applicants state that once the Proposed Transaction has closed, "Applicants will be absolutely and unequivocally committed to fulfilling *all* of the commitments they have made, including the commitment to construct the transmission projects that implement permanent mitigation."[212] As discussed in greater detail below, the Commission accepts Applicants' commitment to construct the transmission upgrades described in the March 26 Compliance Filing, and makes fulfillment of that commitment an express condition of this order and the Proposed Transaction. As noted above, Applicants have indicated that completion of some of the seven proposed Transmission Expansion Projects are dependent upon the completion of the Greenville-Kinston Dupont 230 kV Line and the cooperation of two other utilities with whom Applicants have entered into memoranda of understanding under which the two utilities have agreed to negotiate binding agreements to undertake certain transmission projects. The Commission expects Applicants to meet their commitment to build the seven proposed transmission upgrades irrespective of these contingencies. In order to provide assurance that Applicants are progressing towards

[207] *OG&E-Redbud I*, 124 FERC ¶ 61,239 at P 50.

[208] March 26 Compliance Filing at 8, n.7.

[209] March 26 Compliance Filing at n.7.

[210] March 26 Compliance Filing at n.7.

[211] March 26 Compliance Filing at 9.

[212] Applicants May 1 Answer at 3-4.

completing the Transmission Expansion Projects in a timely manner, Applicants must provide the Commission within 15 days of the issuance of this order with copies all of the binding agreements needed to construct the Transmission Expansion Projects, which were to be negotiated with American Electric Power and Dominion Virginia Power.

84. Applicants have also indicated that it will take up to three years to complete the Transmission Expansion Projects. In order to track Applicants' progress regarding the transmission upgrades, the Commission will require the Independent Monitor to provide periodic reports on the status of the Transmission Expansion Projects every three months, with the first report due not later than the last day of the third full month after the Proposed Transaction is consummated and the final report due within 30 days after the last of the seven proposed transmission projects has been placed into service. In addition, Applicants must inform the Commission of any changes in circumstances that would reflect a departure from the facts that the Commission has relied upon in authorizing the Proposed Transaction, including facts related to its commitment to complete the Transmission Expansion Projects.

85. In the interim, pending completion of the Transmission Expansion Projects, Applicants propose to sell capacity and energy pursuant to the four Power Sales Agreements. The Commission accepts Applicants' proposed interim mitigation, as revised below, because it will mitigate the adverse competitive effects of the Proposed Transaction until the Transmission Expansion Projects are completed. Applicants, however, must revise certain elements of the Revised Mitigation Proposal, such as prohibiting themselves from having priority to repurchase the energy sold pursuant to the Power Sales Agreements, and increasing the Independent Monitor's oversight, as discussed below.

86. The Commission concludes that the combination of the interim sales and the commitment to build the proposed Transmission Expansion Projects, as revised below, will sufficiently mitigate the adverse competitive impacts of the Proposed Transaction identified in the Merger Order. Further, the Commission's authorization for Applicants to merge is expressly conditioned upon Applicants fulfilling their interim and permanent mitigation commitments. Applicants must notify the Commission within 15 days of the issuance of this order as to whether they accept the Commission's revisions to the Revised Mitigation Proposal.

1. <u>The proposed permanent mitigation</u>

87. Applicants have shown that, except for one season/load period discussed below, the seven proposed Transmission Expansion Projects mitigate the screen failures identified by the Commission in the Merger Order. Specifically, Applicants' supporting analysis for the Duke Energy Carolinas and the Progress Energy Carolinas-East BAAs demonstrates that for the base case and 10 percent price sensitivity scenarios, the proposed Transmission Expansion Projects will eliminate the adverse competitive effects

identified by the Commission in the Merger Order.[213] For example, in the Merger Order, the Commission found that, without mitigation, the Proposed Transaction would increase market concentration in the Summer Off-Peak and Winter Off-Peak season/load periods by significant amounts.[214] With respect to the Progress Energy Carolinas-East BAA, the Commission found that, without mitigation, the Proposed Transaction would increase the market concentration in the Summer Off-Peak periods by a significant amount.[215] The DPT results provided in Applicants April 13 Information Request Answer demonstrate

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[213] In making its findings, the Commission relies on the information provided in Applicants April 13 Information Request Answer. Although the DPT results in that pleading are similar to the DPT results provided in the March 26 Compliance Filing, the Commission believes that the DPT in Applicants April 13 Information Request Answer provides a more accurate assessment of the impacts of the proposed Transmission Expansion Projects. Further, in Applicants April 13 Information Request Answer, Applicants provided details of seven changes to the modified seasonal benchmark models other than the seven proposed Transmission Expansion Projects and the Greenville-Kinston Dupont 230 kV line. Applicants April 13 Information Request Answer at 3-5. Applicants explain that "[n]one of these changes affect the SIL assumptions that were used in the Merger Application, as they do not affect the limit that determines the SILs prior to transmission expansion, but only the effectiveness of the expansion projects." Applicants April 13 Information Request Answer at 3. The Commission agrees that these changes do not affect the specific limits that determined the SILs prior to transmission expansion. Nevertheless, in order to achieve the benefits that Applicants claim will result from the seven Transmission Expansion Projects, the Commission expects Applicants to implement the changes referenced in Applicants April 13 Information Request Answer no later than the date that the last of the seven Transmission Expansion Projects are in service. *See* Applicants April 13 Information Request Answer at 4-5, (c)(i). Our authorization to merge is based upon these changes being implemented in this timeframe.

[214] Specifically, in the base case scenario for the Duke Energy Carolinas BAA, the Commission found that the Proposed Transaction would increase Applicants' market share to 62.4 percent in the Summer Off-Peak season/load period and 46.3 percent in the Winter Off-Peak season/load period. As the Commission noted, the HHIs would have increased by 529 and 299, respectively, if the Commission had approved the Proposed Transaction without mitigation. Merger Order, 136 FERC ¶ 61,245 at P 135, Table 1.

[215] Specifically, in the base case scenario for the Progress Energy Carolinas-East BAA, the Commission found that the Proposed Transaction would increase Applicants' market share to 45.4 percent in the Summer Off-Peak season/load period, and the HHI would increase by 894. Merger Order, 136 FERC ¶ 61,245 at P 135, Table 1.

that the proposed Transmission Expansion Projects adequately mitigate the adverse effects of the Proposed Transaction on competition. Applicants show that the Transmission Expansion Projects will decrease market concentration levels in the Duke Energy Carolinas BAA to below pre-merger levels in most season/load periods.[216] For example, Applicants' analysis shows that once the proposed Transmission Expansion Projects are completed, the market concentration levels in the Duke Energy Carolinas BAA for the Summer Off-Peak and Winter Off-Peak seasons/load periods will decrease by 1,046 and 547 points, respectively, from pre-merger levels.[217]

88. As Applicants note, the Revised Mitigation Proposal resolves all of the screen failures identified by the Commission in the Merger Order except for one failure in the Progress Energy Carolinas-East BAA during the Summer Off-Peak season/load period.[218] According to Applicants, this failure does not present a competitive concern. Applicants observe that the Commission has stated that where it encounters HHI screen failures, it will focus on a firm's ability and incentive to withhold output in order to drive up market prices, which Applicants claim they do not possess.[219] Applicants also argue that the single remaining failure does not represent a systematic market power concern.[220] Nevertheless, Applicants state that if the Commission deems it necessary, they will

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[216] Applicants April 13 Information Request Answer, Exhibit WHH-5 (Revised).

[217] Applicants April 13 Information Request Answer, Exhibit WHH-5 (Revised). In the Duke Energy Carolinas BAA, for the Summer Off-Peak season/load period, Applicants calculate a pre-merger HHI of 3,434. Applicants show that once they complete the Transmission Expansion Projects, the HHI for the Summer Off-Peak season/load period will decrease to 2,388 (a difference of 1,046 points). For the Winter Off-Peak season/load period, Applicants calculate a pre-merger HHI of 1,963. Applicants show that once they complete the Transmission Expansion Projects, the HHI for the Winter Off-Peak season/load period will decrease to 1,416 (a difference of 547 points).

[218] During this season/load period, the post-merger HHI is 1,402, a 101 point increase over the pre-merger HHI. The market share in this period is 35.0 percent. Applicants April 13 Information Request Answer, Exhibit WHH-6 (Revised). As noted above, mergers in moderately concentrated markets (with an HHI greater than or equal to 1,000 but less than 1,800) that produce an HHI increase over 100 points potentially raise significant competitive concerns. *See* n.55, *supra.*

[219] March 26 Compliance Filing at 14-15.

[220] March 26 Compliance Filing at 14.

establish a transmission set-aside of 25 MW of firm transmission capacity, the Stub Mitigation, in order to remedy the remaining screen failure.[221]

89. The Commission accepts Applicants' proposal to implement the Stub Mitigation and conditions approval of the Proposed Transaction on Applicants abiding by that commitment. Applicants' August 29 DPT, which was the basis for the Commission's decision in the Merger Order, showed that the largest HHI change due to the Proposed Transaction occurred in the Progress Energy Carolinas-East BAA in the Summer Off-Peak season/load period in a highly concentrated market.[222] In that order, we noted that the screen violation was "severe."[223] Although the Revised Mitigation Proposal may reduce the degree of the screen failure, it fails to eliminate it. Accordingly, the Commission believes that the continued failure in the Progress Energy Carolinas-East BAA in the Summer Off-Peak season/load period warrants requiring Applicants to implement the Stub Mitigation they have voluntarily proposed.

90. While Applicants have demonstrated that the proposed Transmission Expansion Projects will remedy the adverse competitive effects of the Proposed Transaction, Applicants have explained that the proposed Transmission Expansion Projects will take up to three years to complete. Although Applicants have proposed interim mitigation to mitigate the adverse competitive effects of the Proposed Transaction while the Transmission Expansion Projects are being completed, the Commission finds it appropriate to monitor Applicants' progress towards completing the Transmission Expansion Projects. Accordingly, the Commission will accept Applicants' offer to "expand the scope of work" performed by the Independent Monitor to include:

> (a) monitoring the extent to which the Applicants are pursuing the construction of the proposed projects within the scope and time frame identified by [Applicants' witnesses] and reporting to the Commission if

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[221] Applicants state that the Stub Mitigation will "remain in effect unless and until the Commission rules in the future that it [is] no longer required." March 26 Compliance Filing at 17.

[222] *See* Merger Order, 136 FERC ¶ 61,245 at P 137, Table 1.

[223] *See* Merger Order, 136 FERC ¶ 61,245 at P 137 ("This HHI change is over 17 times greater than HHI changes that 'potentially raise significant competitive concerns," and almost nine times greater than HHI changes that are 'presumed likely to create or enhance market power.'").

> this commitment is violated; and (b) reporting to the Commission when the projects have been completed and placed in service.[224]

91. In order to track Applicants' progress regarding the transmission upgrades, the Commission will require the Independent Monitor to provide periodic reports on the status of the transmission upgrades every three months, with the first report due not later than the last day of the third full month after the Proposed Transaction is consummated and the final report due within 30 days after the last of the seven proposed transmission projects has been placed into service.[225] If the Transmission Expansion Projects are not completed as Applicants commit, then Applicants will not have satisfied the commitments upon which the Commission is granting authorization to merge, and the Commission will require a further mitigation plan and steps to mitigate the screen failures, which might include virtual or physical divestitures, pursuant to our authority under sections 203(b) and 309 of the FPA.[226] The Commission may also issue any other supplemental orders as appropriate. Moreover, Applicants must inform the Commission of any change in circumstances that would reflect a departure from the facts that the Commission relied upon in authorizing the Proposed Transaction, including facts related to Applicants' commitment to complete the proposed Transmission Expansion Projects.[227] Consistent with Applicants' representations in the settlement they have reached with North Carolina Commission Staff,[228] the Commission will require Applicants to hold transmission and wholesale requirements customers harmless from the costs of the Transmission Expansion Projects in accordance with the hold harmless commitment, as set forth in the Merger Order.[229] In the Settlement Agreement with North Carolina Commission Staff, Applicants agreed:

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[224] Applicants May 1 Answer at 11.

[225] *See, e.g., Ameren Services Co.*, 101 FERC ¶ 61,202, at 61,842 (2002).

[226] 16 U.S.C. § 824b(b) (2006); 16 U.S.C. § 825h (2006).

[227] *See OG&E-Redbud*, 124 FERC ¶ 61,239 at PP 50-51.

[228] Supplemental Agreement and Stipulation of Settlement, Docket Nos. E-2, Sub 998, and E-7, Sub 986 (May 8, 2012) (Settlement Agreement with North Carolina Commission Staff).

[229] Merger Order, 136 FERC ¶ 61,245 at P 147. In the Merger Application, Applicants stated that for the five-year hold harmless period, they would "not seek to include merger-related costs in their transmission revenue requirements…." Merger

(continued…)

> Duke Energy and Progress Energy have represented to the FERC in their Revised Mitigation Proposal that "there currently is no plan to construct any of [the proposed transmission projects] absent the Merger" and that "[i]t is clearly not foreseeable and reasonably certain that, absent the Merger, these projects would be constructed in the next two to three years, as the Applicants now propose." DEC and PEC have committed not to assign costs associated with Permanent Transmission Mitigation projects into their wholesale transmission rates until the later of the expiration of the five-year FERC hold harmless period or such time as they have received regulatory approval to assign those costs to their retail native loads, effective on the date they are first permitted to begin recovering those costs. Settlement Agreement with North Carolina Commission Staff at 5 (quoting March 26 Compliance Filing at 10).

92. As noted above, protestors challenge Applicants' commitment to construct the Transmission Expansion Projects. City of New Bern, for example, argues that Applicants have not actually committed to construct the Transmission Expansion Projects,[230] and that the proposed transmission upgrades "may never actually materialize."[231] City of New Bern also alleges that by making construction of the upgrades contingent upon acceptable resolution of state ratemaking issues, Applicants further increase the uncertainty about whether they will complete the Transmission Expansion Projects.[232] The Commission is satisfied that Applicants have addressed these concerns. Applicants have stated that:

> [t]he need to reach agreement on the retail rate treatment for the transmission projects will be satisfied before the [Proposed Transaction] closes. The Applicants' commitment to construct the transmission projects after the [Proposed Transaction] closes is completely unaffected by this need. Although the Applicants do not believe it to be necessary, they reaffirm here their commitment to construct the transmission expansion projects identified in [the Revised Mitigation Proposal] after the [Proposed

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Application at 33. The Commission notes that these costs include all of the costs related to the Transmission Expansion Projects, including those related to operating procedures.

[230] City of New Bern Protest of Revised Mitigation Proposal at 11.

[231] City of New Bern Protest of Revised Mitigation Proposal at 10.

[232] City of New Bern Protest of Revised Mitigation Proposal at 11.

Transaction] closes. Once the [Proposed Transaction] closes, this commitment will not be conditioned in any way.[233]

93. Accordingly, if Applicants cannot reach an agreement with the North Carolina Commission on the retail rate treatment of the Transmission Expansion Projects, the Proposed Transaction will not close, and the impact of the Proposed Transaction on horizontal competition will become moot. The Commission considers Applicants' statements to be an unconditional commitment to build the proposed Transmission Expansion Projects if the Proposed Transaction closes. Thus, we reject protestors' assertions that Applicants have not made an unconditional commitment to complete the Transmission Expansion Projects once the Proposed Transaction closes.[234]

94. The Commission also disagrees with City of New Bern's claim that two of the proposed Transmission Expansion Projects do not satisfy the Commission's mitigation requirements. According to City of New Bern, replacement of the Antioch transformers and the construction of the third Lilesville-Rockingham 230 kV Line, the two upgrades that have the most significant impact on Applicants' SILs, are ineligible to be counted as mitigation based on Commission precedent because they are "foreseeable and reasonably certain changes in the regional market."[235] City of New Bern argues that because these two projects have appeared in NCTPC transmission plans on multiple occasions and are upgrades that "would usually be undertaken in the ordinary course of business by an efficient utility," they should not be considered as mitigation by the Commission.[236] City of New Bern asserts that once these projects are removed from the set of proposed transmission upgrades, the increases to Applicants' SILs are not as great, and the market concentration levels resulting from "crediting" the remaining five transmission upgrades show "significant and severe exceedance of the relevant market concentration thresholds."[237]

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[233] Applicants May 1 Answer at 8.

[234] For the same reasons, we dismiss EPSA's claim that the proposed projects are "fraught with the potential for delay." EPSA Comments on Revised Mitigation Proposal at 5.

[235] City of New Bern Protest of Revised Mitigation Proposal at 12-13 (citing *Oklahoma Gas & Elec. Co.*, 105 FERC ¶ 61,297, at P 32 (2003)).

[236] City of New Bern Protest of Revised Mitigation Proposal at 15.

[237] City of New Bern Protest of Revised Mitigation Proposal at 14.

95. Although City of New Bern has demonstrated that the Antioch transformer replacement and construction of the third Lilesville-Rockingham 230 kV Line have appeared in prior NCTPC transmission plans, the city's evidence also shows that these projects have been deferred into the future. City of New Bern notes that "[b]eginning with the 2008 NCTPC Report…replacement of the Antioch banks was no longer listed as a planned upgrade."[238] Specifically, "[the Antioch transformer replacement] was deferred from the 2013 timeframe…. The 2008 Study indicates that the upgrade will not be required until 2024, which is beyond the 10 year planning horizon."[239] Similarly, City of New Bern states that, according to the 2010 NCTPC Report, the third Lilesville-Rockingham 230 kV Line was "deferred beyond the ten-year planning horizon of the 2010 Plan."[240] Later in the same report, the project is listed as "Removed."[241]

96. The Commission notes that Applicants have explained that neither of the projects that City of New Bern challenges was "ever commenced" and that both were taken out of Applicants' transmission plans.[242] Applicants also state that the current NCTPC annual study report and Duke Energy Carolinas' and Progress Energy Carolinas' internal transmission plans do not include either of these projects. Accordingly, based on the evidence in the record, the Commission concludes that the Antioch transformer replacement and the third Lilesville-Rockingham 230 kV Line are not foreseeable and reasonably certain changes in the regional market and are therefore properly considered as mitigation for the Proposed Transaction.

2. The proposed interim mitigation.

97. Because the adverse competitive effects identified in the Merger Order will continue to exist during the construction of the Transmission Expansion Projects, Applicants have proposed to sell capacity and energy pursuant to the Power Sales

[238] City of New Bern Protest of Revised Mitigation Proposal, Exhibit No. NCC-1, Affidavit of Whitfield A. Russell at P 16 (Russell Aff.).

[239] City of New Bern Protest of Revised Mitigation Proposal, Exhibit No. NCC-1, Russell Aff. at P 16.

[240] City of New Bern Protest of Revised Mitigation Proposal, Exhibit No. NCC-1, Russell Aff. at P 22.

[241] City of New Bern Protest of Revised Mitigation Proposal, Exhibit No. NCC-1, Russell Aff. at P 22.

[242] Applicants May 1 Answer at 14.

Agreements as interim mitigation and to have the Independent Monitor monitor compliance with their commitments. The Commission concludes that the combination of the sales pursuant to the Power Sales Agreements and the Independent Monitor's oversight of those sales, as revised below, constitute effective mitigation that will be in place at the time the Proposed Transaction is consummated.

98. The Commission disagrees with protestors that argue that, by using a modified version of the *force majeure* clause that appears in the EEI Master Agreement, Applicants have transformed the Power Sales Agreements into transmission contingent agreements, and that that modification disqualifies the Power Sales Agreements as effective interim mitigation measures. Importantly, the modified *force majeure* clause does not excuse Applicants' obligation to deliver energy to buyers at the delivery points specified in the Power Sales Agreements. In addition, that provision does not give Applicants the right to interrupt deliveries to the buyers under the Power Sales Agreements in order to serve Applicants' retail and wholesale native load. Rather, as explained in Applicants May 1 Answer, the modified *force majeure* provision only excuses buyers' "obligation to perform, and even then only under very limited circumstances."[243] Further, Applicants are required to pay liquidated damages to buyers if Applicants fail to deliver, unless Applicants' failure is excused by *force majeure*. Accordingly, the Commission is not persuaded by City of Orangeburg's contention that buyers under the Power Sales Agreements will face the constant risk of product unavailability due to Applicants' need to use their system resources to serve retail and wholesale native load.

99. The Commission recognizes that in instances where transmission to a buyer's proposed sink is unavailable or interrupted, the Power Sales Agreements excuse both the buyer's and seller's failure to perform.[244] However, this alone does not disqualify the Power Sales Agreements from serving as interim mitigation where, as here, the ability to invoke *force majeure* due to transmission unavailability is entirely in the control of the buyer. Moreover, we are not convinced by protestors that the Power Sales Agreement buyers will have any financial incentives to engage in the kind of strategic behavior that protestors imagine simply to avoid the obligation to take energy at the delivery point, thereby leaving Applicants in control of the energy that would otherwise be sold pursuant to the Power Sales Agreements.

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[243] Applicants May 1 Answer at 18.

[244] *See, e.g.,* March 26 Compliance Filing, Exhibit C, Duke Energy Carolinas-Cargill Power Sales Agreement at 4 ("If ... Buyer will not take delivery of the full Quantity of Energy, then [Duke Energy Carolinas] shall be excused from its obligation to deliver the quantity of Energy").

100. The Commission also disagrees with City of Orangeburg that the Power Sales Agreements suffer from the same defects that the Commission found unacceptable in *Allegheny Energy*. In *Allegheny Energy*, the merging parties proposed, as a mitigation measure, to make short-term power sales from a specific generating station for an indeterminate period.[245] Those merging parties had not secured agreements with any buyers and had also not guaranteed that short-term transmission service would be available on the merged company's system to deliver the power to the buyer.[246] Under those circumstances, the Commission concluded that there were no assurances that the entire output of the generating station would be sold, and that other terms and conditions of the proposed sale made it likely that there would be limited demand for the output.[247] The Commission stated that it remained concerned that if part or all of the output of the generating station went unsold, the station's output would remain within the control of the applicants and they could withhold it from the market and thereby drive up electricity prices.[248]

101. Although the Prior Mitigation Proposal suffered from many of the flaws identified by the Commission in *Allegheny Energy*, the proposed Power Sales Agreements largely rectify those flaws. For example, Applicants have secured agreements with three specified buyers that have committed to take specified quantities of energy and capacity in specified hours, and under those agreements Applicants do not have any "recall" rights to the energy. Further, in this case the Power Sales Agreements are interim mitigation measures that will remain in place only until Applicants have completed the Transmission Expansion Projects. Moreover, as noted above, the terms of the Power Sales Agreements require Applicants to deliver energy to buyers at the specified delivery points and do not allow Applicants to avoid this obligation due to transmission unavailability up to the delivery points. Thus, we are satisfied that Applicants effectively will cede control of the capacity and energy to be sold under the Power Sales Agreements.

102. Even with these assurances, the Commission acknowledges concerns that the Power Sales Agreements may excuse buyers from purchasing the energy if transmission service from the delivery point to the buyer's proposed sink is unavailable, interrupted, or curtailed for any reason. Although Applicants have provided assurances that it is

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[245] *Allegheny Energy*, 84 FERC ¶ 61,223 at 62,067.

[246] *Allegheny Energy*, 84 FERC ¶ 61,223 at 62,070.

[247] *Allegheny Energy*, 84 FERC ¶ 61,223 at 62,070.

[248] *Allegheny Energy*, 84 FERC ¶ 61,223 at 62,070-62,071.

unlikely that buyers will invoke *force majeure* due to transmission unavailability,[249] if the actual quantity of energy sold is less than the quantities of energy specified in the Power Sales Agreements, Applicants would effectively retain control over the energy, and therefore market concentration levels could remain high.

103. To address this remaining concern, the Commission requires that Applicants abide by the following. First, in Applicants May 1 Answer, Applicants state:

> the transmission contingency relieves the power marketers of their obligation to take delivery of energy only when transmission is not available to the marketers' proposed sink. Even then, the power marketers can always choose to take delivery of the energy at the Delivery Point and sell to a customer in the DEC or PEC BAAs, or to customers located outside of the BAAs, even if transmission is unavailable to a particular market. Applicants May 1 Answer at 21.

We direct Applicants that, in the context of the interim mitigation proposed here, Applicants cannot use control over their transmission systems to thwart sales under the Power Sales Agreements. This should minimize the instances in which buyers would be required to declare a force majeure event in order to not take possession of the power, thus undermining the proposed mitigation. Moreover, the Independent Monitor will report within 3 business days any hours in which buyers did not purchase the full amount of energy Applicants are required to deliver under the Power Sales Agreements.

104. Second, the Commission will condition acceptance of the Revised Mitigation Proposal upon Applicants not having any priority right over other potential buyers to re-purchase any of the energy and/or capacity sold by Applicants pursuant to the Power Sales Agreements. Third, Applicants must not enter into transactions with the counterparties to the Power Sales Agreements except on a spot (day-ahead or shorter) basis.

105. Fourth, as noted above, the energy price under the Power Sales Agreements is based on the natural gas price reported in Platts Gas Daily for Transco Zone 5. The Commission believes that, in the context of the Revised Mitigation Proposal and the Power Sales Agreements, basing the natural gas price on a more liquid pricing point than Transco Zone 5 would be more appropriate. According to data from Platts between January 2010 and the present there have only been 21 transactions on average per day at Transco Zone 5 whereas there have been 85 transactions on average per day, or four

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[249] *See e.g.* Applicants May 1 Answer at 5, 20-21, Exhibit A.

times as many, at Transco Zone 4. The reduced liquidity at Transco Zone 5 is significant because it could enable a small number of transactions to affect the Transco Zone 5 price index. The Commission must be assured that the price index that is used as part of Applicants' mitigation is based on a sufficiently liquid trading hub because, if it is not, the result could be an adverse effect on competition. Accordingly, for the duration of the Power Sales Agreements, Applicants must either limit the price they pay for new purchases of natural gas at Transco Zone 5 to the index price or replace Transco Zone 5 with Transco Zone 4.

106. Finally, on each occasion when Applicants sell power under the Power Sales Agreements, Applicants must simultaneously post on their electronic bulletin boards the amount of power that was sold under the Power Sales Agreement(s) and for what duration. This requirement will provide transparency and notify interested parties that the buyers under the Power Sales Agreements may have power available to sell to third parties, and therefore reduce the likelihood that the three buyers under the Power Sales Agreements would need to sell the energy purchased under those agreements back to Applicants. These conditions are necessary to prevent Applicants from being able to effectively maintain control of the capacity and energy that would otherwise be sold under the Power Sales Agreements, which, if that occurred, would cause Applicants to fail the merger screens.

107. Applicants must also revise the Revised Mitigation Proposal to expand the scope of the Independent Monitor's duties to include monitoring the purchases made under the Power Sales Agreements on a daily, ongoing basis. Accordingly, in addition to the Independent Monitor's performance of the duties set out in the Monitoring Agreement provided with the March 26 Compliance Filing,[250] the Independent Monitor must also monitor the purchases under the Power Sales Agreements for: (1) hours in which buyers did not purchase the full amount of energy Applicants are required to deliver under the Power Sales Agreements; and (2) hours in which any buyer under the Power Sales Agreements sells to either Duke Energy Carolinas or Progress Energy Carolinas in the Duke Energy Carolinas and/or Progress Energy Carolinas BAAs an amount of energy or capacity equal to or more than five percent of the amount of energy purchased by the buyer under the Power Sales Agreement. The Independent Monitor must notify the Commission within 3 business days if, in any hour and for any reason, the actual purchases under the Power Sales Agreements are less than the quantities Applicants are required to deliver in those agreements. Applicants must notify the Independent Monitor within two business days, and the Independent Monitor must notify the Commission within three business days, if a buyer sells to either Duke Energy Carolinas or Progress

[250] *See* March 26 Compliance Filing, Exhibit D, Monitoring Agreement.

Energy Carolinas in the Duke Energy Carolinas and/or Progress Energy Carolinas BAAs an amount of energy or capacity equal to more than five percent of the amount of energy or capacity purchased by the buyer under the Power Sales Agreement. Such notification must include the date, hour, product name, quantity and price of such sale(s) to Applicants, as well as the quantity and price of the energy or capacity purchased by the buyer from Applicants during that/those same hour(s). These additional Independent Monitor functions will enable the Commission to detect any attempts by Applicants to circumvent the interim mitigation.

108. Applicants must also expand the scope of the reports the Independent Monitor is required to submit to the Commission pursuant to the Revised Mitigation Proposal.[251] In addition to the information that Applicants have proposed to include in those reports in the Monitoring Agreement, the Independent Monitor's reports must also: (1) document the quantities of energy and capacity purchased under the Power Sales Agreements; (2) document the amount of energy purchased by Duke Energy Carolinas and Progress Energy Carolinas from the Power Sales Agreement buyers; and (3) document when a buyer under a Power Sales Agreement invokes *force majeure* because transmission from the delivery point(s) under the Power Sales Agreement to buyer's proposed ultimate sink is interrupted or is not available in the Duke Energy Carolinas and Progress Energy Carolinas BAAs and in BAAs or markets that are first-tier to Duke Energy Carolinas and Progress Energy Carolinas. This additional information will enable the Commission to monitor whether Applicants are abiding by the terms of the interim mitigation.

109. Finally, protestors argue that the Commission should reject the Power Sales Agreements simply because they provide for negative capacity prices at certain times (i.e., Applicants will pay buyers to take capacity during certain time periods). We disagree with City of Orangeburg that these prices "[bely] Applicants' claim of having engaged in a meaningful divestiture of system resources."[252] As Applicants note, the Commission took issue with the Prior Mitigation Proposal because Applicants failed to demonstrate that they would relinquish control over the energy that they proposed to offer to sell.[253] The Commission did not prescribe a price range or particular price terms

[251] *See* March 26 Compliance Filing, Exhibit D, Monitoring Agreement at 1.C.(1). Under section 1.C.(1) of the Monitoring Agreement, the Independent Monitor is required to submit, within 30 days following the conclusion of each winter and summer season, a report regarding Applicants' compliance or non-compliance with the interim mitigation proposal.

[252] City of Orangeburg Comments on Revised Mitigation Proposal at 25.

[253] Applicants May 1 Answer at 17.

and does not find that negative capacity prices in some time periods constitute sufficient justification to reject the proposed interim mitigation. Nevertheless, in order to protect Applicants' transmission and wholesale requirements customers from any losses that Applicants may incur under the Power Sales Agreements, the Commission will require Applicants to hold customers harmless from those losses in accordance with the hold harmless commitment, as set forth in the Merger Order.[254]

3. Other concerns

110. The Commission rejects City of Orangeburg's arguments pertaining to the state regulatory conditions for the same reasons that we did so in the Merger Order – namely, that City of Orangeburg has "failed to demonstrate that the alleged harms to competition stem from the Proposed Transaction."[255] The alleged harms that City of Orangeburg complains of are based on existing state regulatory policies, which are currently in place and will continue in effect regardless of whether the Proposed Transaction goes forward. Consequently, we will not address these arguments here.

111. FMPA also reiterates arguments that it has advanced in other pleadings, specifically in its request for rehearing of the Merger Order and in its original protest of the Merger Application. As before, FMPA's arguments focus on the Commission's determination in the Merger Order that "Duke Energy and Progress Energy have demonstrated that they do not conduct business in the same geographic market in Florida."[256] The March 26 Compliance Filing, however, pertains entirely to the Commission's competitive concerns with regard to the Carolinas markets. Accordingly, we will not address FMPA's arguments here, but will address them on rehearing of the Merger Order.

112. Finally, the Commission declines to require Applicants to join an RTO, as EPSA advocates.[257] In both the Merger Order and the Compliance Order, the Commission explained that possible mitigation proposals could include, but were not limited to, forming or joining an RTO.[258] The Commission explained that it would review any

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[254] *See* Merger Order, 136 FERC ¶ 61,245 at P 147.

[255] Merger Order, 136 FERC ¶ 61,245 at P 147.

[256] Merger Order, 136 FERC ¶ 61,245 at P 151.

[257] EPSA Comments on Revised Mitigation Proposal at 3.

[258] Merger Order, 136 FERC ¶ 61,245 at P 145; Compliance Order, 137 FERC ¶ 61,210 at P 4.

proposal by Applicants to ensure that "the Proposed Transaction, as mitigated, will not result in an adverse effect on competition and is consistent with the public interest."[259] The Commission finds that, as conditioned above, the Revised Mitigation Proposal accomplishes this objective.

4. Conclusion

113. For the reasons stated above, the Commission finds, pursuant to the Merger Policy Statement, related regulations, and precedent, that the Proposed Transaction, as initially submitted by Applicants, as supplemented by the Revised Mitigation Proposal, Applicants April 13 Information Request Answer and Applicants May 1 Answer, and as revised herein, will not have an adverse effect on competition. If Applicants elect to accept the Commission's revisions to the Revised Mitigation Proposal, Applicants should notify the Commission within 15 days of the issuance of this order. In summary, our acceptance of the Revised Mitigation Proposal is subject to the following modifications:

- Applicants must place the proposed Transmission Expansion Projects into service by June 1, 2015.
- Within 15 days of the issuance of this order, Applicants must provide the Commission with copies of all of the binding agreements needed to construct the Transmission Expansion Projects that were to be negotiated with American Electric Power and Dominion Virginia Power.
- Applicants must implement their Stub Mitigation proposal.
- The Independent Monitor must provide periodic reports on the status of the transmission upgrades every three months, with the first report due not later than the last day of the third full month after the Proposed Transaction is consummated and the final report due within 30 days after the last of the seven proposed transmission projects has been placed into service.
- Applicants must hold transmission and wholesale requirements customers harmless from the costs of the Transmission Expansion Projects in accordance with the hold harmless commitment set forth in the Merger Order.
- Applicants cannot use control over their transmission systems to thwart sales under the Power Sales Agreements.

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[259] Merger Order, 136 FERC ¶ 61,245 at P 146.

- Applicants must not have any priority right over other potential buyers to re-purchase any of the energy and/or capacity sold by Applicants pursuant to the Power Sales Agreements.

- For so long as the interim mitigation measures shall remain in place, Applicants must not enter into transactions with the counterparties to the Power Sales Agreements except on a spot (day-ahead or shorter) basis.

- For the duration of the Power Sales Agreements, Applicants must either limit the price they pay for new purchases of natural gas at Transco Zone 5 to the index price or replace Transco Zone 5 with Transco Zone 4.

- On each occasion when Applicants sell power under the Power Sales Agreements, Applicants must simultaneously post on their electronic bulletin boards the amount of power that was sold under the Power Sales Agreement(s) and for what duration.

- The Independent Monitor must monitor the purchases under the Power Sales Agreements for (1) hours in which buyers did not purchase the full amount of energy Applicants are required to deliver under the Power Sales Agreements; and (2) hours in which any buyer under the Power Sales Agreements sells to either Duke Energy Carolinas or Progress Energy Carolinas in the Duke Energy Carolinas and/or Progress Energy Carolinas BAAs an amount of energy or capacity equal to or more than five percent of the amount of energy or capacity purchased by the buyer under the Power Sales Agreement.

- The Independent Monitor must notify the Commission within three days if, in any hour and for any reason, the actual purchases under the Power Sales Agreements are less than the quantities offered in those agreements.

- Applicants must notify the Independent Monitor within two business days, and the Independent Monitor must notify the Commission within three business days if a buyer sells to either Duke Energy Carolinas or Progress Energy Carolinas in the Duke Energy Carolinas and/or Progress Energy Carolinas BAAs an amount of energy or capacity equal to or more than five percent of the amount of such energy or capacity purchased by the buyer under the Power Sales Agreement. Such notification must include the date, hour, product name, quantity, and price of such sale(s) to Applicants, as well as the quantity and price of the energy or capacity purchased by the buyer from the Applicants during that/those same hour(s).

- In addition to the information required under section 1.C.(1) of the Monitoring Agreement, the Independent Monitor must also: (1) document the quantities of energy and capacity purchased under the Power Sales Agreements; (2) document the amount of energy purchased by Duke Energy Carolinas and Progress Energy Carolinas from the counterparties to the Power Sales Agreements; and

(3) document when a buyer under a Power Sales Agreement invokes *force majeure* because transmission from the delivery point(s) under the Power Sales Agreement to buyer's proposed ultimate sink is interrupted or is not available in the Duke Energy Carolinas and Progress Energy Carolinas BAAs and in BAAs or markets that are first-tier to Duke Energy Carolinas and Progress Energy Carolinas.

- Applicants must hold transmission and wholesale requirements customers harmless from losses that Applicants may incur under the Power Sales Agreements in accordance with the hold harmless commitment set forth in the Merger Order.

V. The Power Sales Agreements

114. In addition to proposing that the four Power Sales Agreements serve as interim mitigation while they complete and put into operation the Transmission Expansion Projects, Applicants also filed the Power Sales Agreements for acceptance under section 205 of the FPA. The terms and conditions of the Power Sales Agreements are described in further detail above,[260] but for every Power Sales Agreement, Applicants state that the parties to the agreements have "expressly waived their right to unilaterally seek from [the Commission] a change in the [agreement] pursuant to Section 205 or 206 of the Federal Power Act."[261] Applicants explain that, consistent with *NRG Power Mktng., LLC v. Me. Pub. Utils. Comm'n*, 130 S.Ct. 693 (2010), "the standard of review for changes to the charges, terms and conditions" of the agreements proposed a "Party, a non-Party, or the [Commission] acting *sua sponte* shall be the 'public interest' standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956)."[262]

115. The Power Sales Agreements appear to be just and reasonable, and have not been shown to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Accordingly, the Commission accepts the Power Sales Agreements effective

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[260] *See* PP 34-39, *supra*.

[261] *See e.g.*, *Master Power Purchase and Sale Agreement between Carolina Power & Light d/b/a Progress Energy Carolinas, Inc. and Morgan Stanley Capital Group, Inc.*, Transmittal Letter at 4, Docket No. ER12-1341-000 (March 26, 2012).

[262] *Master Power Purchase and Sale Agreement between Carolina Power & Light d/b/a Progress Energy Carolinas, Inc. and Morgan Stanley Capital Group, Inc.*, Transmittal Letter at 4, Docket No. ER12-1341-000 (March 26, 2012).

on the date the Proposed Transaction is consummated, and directs Applicants to submit a compliance filing within ten days of the consummation of the Proposed Transaction revising the effective date of the Power Sales Agreements.

The Commission orders:

(A) The March 26 Compliance Filing is accepted, as modified, as discussed in the body of this order. Applicants are directed to notify the Commission within 15 days of the issuance of this order as to whether they accept the Commission's revisions to the Revised Mitigation Proposal.

(B) The Power Sales Agreements are hereby accepted for filing, effective on the date the Proposed Transaction is consummated, as discussed in the body of this order.

(C) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(D) Applicants must submit a compliance filing within ten days of the consummation of the Proposed Transaction revising the effective date of the Power Sales Agreements.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary

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VIENNA

July 11, 2012

Via eTariff

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: *Duke Energy Corporation and Progress Energy, Inc.*
Docket No. ER12-1338-001
Joint Dispatch Agreement (Compliance Filing)

Dear Secretary Bose:

Pursuant to the Commission's order, *Duke Energy Corp. and Progress Energy, Inc.*, 139 FERC ¶ 61,193 (2012) (the "JDA Order"), Duke Energy Corporation ("Duke Energy") on its own behalf and on behalf of its public utility subsidiary, Duke Energy Carolinas, LLC ("DEC"), and Progress Energy, Inc. ("Progress Energy"), on its own behalf and on behalf of its public utility subsidiary, Carolina Power & Light Company ("CP&L"), d/b/a Progress Energy Carolinas, Inc. ("PEC") (collectively, "Applicants"), hereby submit for filing an eTariff-compliant revised Joint Dispatch Agreement ("JDA"), to be designated as DEC's Rate Schedule No. 341, with an effective date of July 2, 2012. In addition, pursuant to the JDA Order, Applicants submit an explanation of whether, and if so, how, co-owners of jointly-owned facilities will share in cost savings resulting from economic dispatch as contemplated under the JDA for each of their existing joint ownership agreements.

On June 8, 2012, the Commission issued the JDA Order, conditionally accepting the JDA and related concurrence filing that had been submitted for filing by Applicants on March 26, 2012.[1] In the JDA Order, the Commission stated that Section 3.2(c)(ii)-(iv) of

1 The JDA was filed by Applicants in Docket No. ER12-1338-000. Progress Energy, on its own behalf and on behalf of CP&L, filed a concurrence to the JDA in Docket No. ER12-1347-001.

the JDA pertained fundamentally to retail ratemaking and that the inclusion of such provisions is not appropriate in a FERC-jurisdictional wholesale agreement. *Id.* at P 37. FERC directed DEC and PEC to omit those provisions from the JDA. *Id.* The Commission also required DEC and PEC to remove the distinction in the JDA between sales to existing non-native load customers and sales to new non-native load customers. *Id.* at P 46. The Commission additionally directed Applicants to submit a compliance filing, within ten days of the consummation of the merger, revising the effective date of the JDA. *Id.* at Ordering Paragraph E. Finally, the Commission directed Applicants to submit an explanation of whether, and if so, how, co-owners of jointly owned facilities will share in cost savings from economic dispatch as contemplated under the JDA for each of their existing joint ownership agreements. *Id.* at P 47.

The merger was consummated on July 2, 2012. The revised JDA transmitted here complies with the Commission's directives in the JDA Order by (a) eliminating the provisions in Section 3.2(c)(ii)-(iv) of the JDA; (b) removing the distinction between sales to existing non-native load customers and sales to new non-native load customers in the JDA; and (c) establishing the effective date of the revised JDA to July 2, 2012, the date the merger was consummated.

Applicants provide the following explanation of whether, and if so, how, co-owners of jointly owned facilities will share in cost savings from economic dispatch as contemplated under the JDA for each of their existing joint ownership agreements:

DEC owns one generating facility, Catawba Nuclear Station, with three co-owners. The three co-owners are North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Association. Each of the co-owners is entitled to a certain percentage of the electric output of Catawba. DEC has no rights to the portion of the output to which the co-owners are entitled. The JDA is an agreement between DEC and PEC which involves the power resources of DEC and PEC only. Because DEC has no rights to the portion of the output of Catawba to which the co-owners are entitled, such output is not subject to the JDA and the co-owners rights are not affected by the JDA. The co-owners do not participate in the joint dispatch under the JDA and do not share in any JDA savings.

PEC owns four generating facilities, Harris, Brunswick, Roxboro and Mayo, with one co-owner, North Carolina Eastern Municipal Power Agency ("NCEMPA"). NCEMPA is entitled to a certain percentage of the electric output of Harris, Brunswick, Roxboro and Mayo. PEC has no rights to the portion of the output to which the co-owners are entitled. The JDA is an agreement between DEC and PEC which involves the power resources of DEC and PEC only. Because PEC has no rights to the portion of the output of the units to which the co-owners are entitled, such output is not subject to the JDA and the co-owners rights are not affected by the JDA. The co-owners do not participate in the joint dispatch under the JDA and do not share in any JDA savings. To the extent the operation of the JDA impacts the dispatch of Roxboro and Mayo, because they are coal plants and their dispatch will be impacted by the price of fuel, PEC has agreed to hold NCEMPA harmless from any negative impacts to the JDA.

Included in this filing are the following materials:

- This transmittal letter describing the JDA Order and the compliance filing;
- Clean Tariff Attachment of the revised JDA, Duke Energy Carolinas, LLC Rate Schedule No. 341; and
- Marked Tariff Attachment of the revised JDA showing additions and deletions in compliance with section 35.10(b) of the Commission's regulations, 18 C.F.R. § 35.10(b).

For the reasons stated herein, Applicants respectfully request that the Commission issue an order accepting this compliance filing.

Respectfully submitted,

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Enclosures

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day caused to be served the foregoing document upon each person whose name is on the official service list in the above-captioned proceeding.

Dated at Washington, D.C., this 11th day of July, 2012.

/s/

Kathryn K. Baran

JOINT DISPATCH AGREEMENT

(CLEAN)

JOINT DISPATCH AGREEMENT

BETWEEN

DUKE ENERGY CAROLINAS, LLC

AND

CAROLINA POWER & LIGHT COMPANY

(Duke Energy Carolinas, LLC Rate Schedule No. 341)

Tariff Submitter: Duke Energy Carolinas, LLC
FERC Tariff Program Name: FERC FPA Electric Tariff
Tariff Title: Tariffs, Rate Schedules and Service Agreements
Tariff Record Proposed Effective Date: 7/2/2012
Tariff Record Title: Joint Dispatch Agreement
Record Content Description: Rate Schedule No. 341
Option Code: A

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JOINT DISPATCH AGREEMENT

THIS JOINT DISPATCH AGREEMENT ("Agreement") is made and entered into as of the ____ day of ___________, 20__, by and between Duke Energy Carolinas, LLC ("DEC"), and Carolina Power and Light Company, doing business as Progress Energy Carolinas, Inc. ("PEC") (collectively referred to herein as the "Parties" and individually as a "Party").

WHEREAS, DEC and PEC are the owners and operators of electric generation, transmission and distribution facilities and are engaged in the business of generating, transmitting, distributing, and selling electric energy to the retail customers in their franchised service areas in North Carolina and South Carolina and also at wholesale to municipalities, cooperatives, and other electric utilities; and

WHEREAS, Duke Energy Corporation, the parent company of DEC, and Progress Energy, Inc., the parent company of PEC, have entered into an Agreement and Plan of Merger dated January 8, 2011 ("Merger"); and

WHEREAS, DEC and PEC intend to jointly dispatch their Power Supply Resources in order to most economically serve the Native Load Customers of both DEC and PEC following the consummation of the Merger; and

WHEREAS, the Parties desire to establish a framework under which the foregoing joint dispatch of the DEC and PEC Power Supply Resources, and the resulting cost savings will be equitably shared between the Parties;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein set forth, the Parties mutually agree as follows:

ARTICLE I
DEFINITIONS

Capitalized terms shall have the meanings set forth below in the Article I. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this Agreement or as commonly used in the electric utility industry.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" or **"BAA"** means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority within which the Balancing Authority maintains the load-resource balance.

"Industry Standards" means all applicable national and regional electric reliability council principles, guides, criteria, and standards and industry standard practices.

"Joint Dispatch" means the dispatch of the Power Supply Resources owned by DEC and PEC respectively on a least cost basis as described in Section 3.1.

"Must Run Resources" means generation units or power purchases that are dispatched out of merit order either due to contractual arrangements or to satisfy operational, reliability or regulatory requirements.

"Native Load" means the load of a Party's Retail Native Load Customers and the retail load of its wholesale customers or its wholesale customers' members served by the Party, directly or indirectly, at Native Load Priority.

"Native Load Customers" means a Party's Retail Native Load Customers plus its wholesale customers that have Native Load served by the Party, for which the Party has an obligation pursuant to current or future wholesale contracts, for the length of such contracts, to engage in planning and to sell and deliver electric capacity and energy in a manner comparable to the Party's service to its Retail Native Load Customers.

"Native Load Priority" means a priority of service equivalent to that provided by the Party to its Retail Native Load Customers.

"NCUC" means the North Carolina Utilities Commission.

"Non-Native Load Sales" means a Party's sales of energy at wholesale, not including transactions between the Parties pursuant to this Agreement or service to Native Load.

"Power Purchases" means purchases of energy at wholesale from sellers other than the other Party.

"Power Supply Resources" means the generating facilities owned by a Party and its Existing Power Purchases and Long Term Power Purchases as further provided herein to be used under this Agreement.

"PSCSC" means the Public Service Commission of South Carolina.

"Retail Native Load Customers" means the retail electric customers for which either DEC or PEC has an obligation under North Carolina and South Carolina law to engage in long-term planning and to supply all generation, transmission, distribution, delivery and sales, and other related services, including installing or contracting for capacity, if needed to provide adequate and reliable service.

"VACAR" means the Virginia-Carolinas sub region within the North American Electric Reliability Corporation's (NERC) SERC Reliability Corporation (SERC).

"VACAR Reserve Sharing Group Arrangement" means the collection of agreements and procedures developed concurrently by the Principals and Operating Representatives of multiple two-party Interchange Agreements as described in the Operating Manual for the VACAR Reserve Sharing Group Arrangement, Revision No. 2, dated January 11, 2011 by and among Dominion, Duke Energy Carolinas, LLC, Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company and South Carolina Public Service Authority, as amended.

ARTICLE II
TERM OF AGREEMENT

2.1 Term.

Subject to approval and any conditions imposed by state and federal regulatory authorities, this Agreement shall take effect upon consummation of the Merger and shall continue in full force and effect for a period of five (5) years from the effective date, continuing thereafter until terminated by mutual agreement of the Parties or by either Party upon five (5) years' written notice to the other Party. If the Parties terminate the Merger prior to its consummation, this Agreement shall have no force or effect.

ARTICLE III
SCOPE OF THE AGREEMENT

3.1 Purpose.

The primary purpose of this Agreement is to provide the contractual basis for the Joint Dispatch of the Power Supply Resources of both DEC and PEC for the purpose of reducing the cost of serving their Native Load Customers to the extent consistent with the provision of reliable electric service, Industry Standards, and applicable laws and regulations ("Joint Dispatch"). This Agreement also shall provide the contractual basis for the sharing of the cost savings resulting from such Joint Dispatch.

3.2 Limits on Scope and Effect of the Agreement.

(a) Nothing in this Agreement is intended to or shall it be construed as:

(i) Providing for or requiring a single integrated electric system;

(ii) Providing for or requiring a single BAA, control area or transmission system;

(iii) Providing for or requiring joint planning or joint development of generation or transmission;

(iv) Providing for or requiring a Party to construct generation or transmission facilities for the benefit of the other Party;

(v) Transferring any rights to generation or transmission facilities from one Party to the other; or

(vi) Providing for or requiring any equalization of the Parties' production costs or rates.

(b) To the extent that the Parties desire to engage in any of the activities or take any of the actions described in Section 3.2 (a), the Parties will amend this Agreement or enter into a separate agreement, subject to approval by the applicable state and federal regulatory authorities.

(c) The participation by both DEC and PEC in this Agreement is voluntary, neither DEC nor PEC is obligated to participate in this Agreement or to make any purchases or sales pursuant thereto and the participation of both DEC and PEC in this Agreement is subject to termination, after notice is provided pursuant to Section 2.1 of this Agreement;

ARTICLE IV
THE JOINT DISPATCHER

4.1 Joint Dispatch Function.

DEC shall act as the Joint Dispatcher, on behalf of DEC and PEC, and shall have the following responsibilities:

(a) Directing the dispatch of both DEC's and PEC's Power Supply Resources;

(b) Making Power Purchases for durations of less than one year ("New Short-Term Power Purchases") to serve the Parties' Native Loads and making Non-Native Load Sales for durations of less than one year from the Parties' Power Supply Resources to the benefit of each Party's Native Load Customers;

(c) Developing and providing bills and billing-related information to effectuate the terms of this Agreement;

(d) Such other activities and duties as may be assigned from time to time by the mutual agreement of the Parties, including but not limited to administration of demand-side resources on behalf of the Parties, subject to applicable state and federal regulatory approvals; and

(e) Incurring the costs necessary to perform its responsibilities under this Agreement, subject to applicable state and federal regulatory approvals.

ARTICLE V
JOINT DISPATCH OF POWER SUPPLY RESOURCES

5.1 Joint Dispatch.

As soon as practicable after the effective date of the Merger, the Joint Dispatcher shall direct the dispatch of the Parties' Power Supply Resources in a manner that: (a) ensures the reliable fulfillment of each Party's service obligations to its Native Load Customers; (b) minimizes the total costs incurred to fulfill each Party's service obligations to its Native Load Customers; and (c) economically satisfies any obligations of each of the Parties with respect to Non-Native Load Sales. To these ends, the Joint Dispatcher shall direct the dispatch of the Power Supply Resources of both Parties consistent with Industry Standards for the safe and reliable operation of both of the Parties' electric systems, the safe and reliable operation of both of the Parties' generating resources, and all applicable laws and regulations, including but not limited to the applicable rules, regulations, orders, and conditions of the NCUC, the PSCSC, the Federal Energy Regulatory Commission ("FERC"), the North American Electric Reliability Corporation ("NERC"), and the SERC Reliability Corporation ("SERC").

5.2 Compliance with Contractual and Regulatory Obligations.

Nothing in this Agreement is intended to diminish or alter the jurisdiction or authority of the NCUC or the PSCSC over the Parties, including, among other things, the jurisdiction and authority to establish the retail rates on a bundled basis for each of the Parties, to impose regulatory accounting and reporting requirements, to impose service quality standards, to require each of the Parties to engage separately in least cost integrated resource planning, or to issue certificates of public convenience and necessity for new generating resources. In addition, nothing in this Agreement is intended to alter the Parties' contractual or regulatory obligations or to provide for Joint Dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following:

(a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and to its other Native Load Customers, and PEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and it its other Native Load Customers;

(b) DEC's obligation to serve its Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales;

(c) PEC's obligation to serve its Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales;

(d) All of DEC's and PEC's respective obligations under wholesale purchase contracts, including contracts for the purchase of energy and capacity on a non-dispatchable basis;

(e) All of DEC's and PEC's respective obligations under wholesale sales contracts, including obligations under full and partial requirements sales contracts;

(f) All of DEC's and PEC's respective obligations under reliability exchange agreements existing prior to the effective date of this Agreement;

(g) DEC's and PEC's respective transmission rights and obligations, including rights and obligations under any transmission service agreements or transmission tariffs and their respective obligations to provide transmission services and to act as the BA for their respective BAAs;

(h) DEC's and PEC's respective individual obligations under the VACAR Reserve Sharing Group Arrangement; and

(i) DEC's and PEC's respective obligations with respect to Must Run Resources to ensure that they are not dispatched in a manner inconsistent with the contractual, operational, reliability or regulatory requirements applicable to such Must Run Resources.

ARTICLE VI
POWER SUPPLY RESOURCES AND NON-NATIVE LOAD SALES

6.1 Generating Resources.

As of the effective date of this Agreement, all generating resources including those that begin commercial operation after the effective date of this Agreement shall be a Power Supply Resource of the Party that owns it and that Party shall be responsible for the capacity costs and energy costs of such Power Supply Resources. If the Parties are subsequently allowed to develop future generating resources jointly or to enter into a reserve sharing agreement with respect to future generating resources, the Parties, at the time that they enter into such an arrangement, and subject to the receipt of all relevant state and federal regulatory approvals, shall agree, upon the allocation of the generation that is the subject of that arrangement for purposes of determining the Parties' Power Supply Resources and responsibility for capacity costs and energy costs.

6.2 Existing Power Purchases and New-Long Term Power Purchases.

The capacity costs (if any) and energy costs associated with Power Purchases contracted for by a Party prior to the effective date of this Agreement ("Existing Power Purchases") and with Power Purchases contracted for by a party after the effective date of this Agreement that are for a year or longer ("New Long-Term Power Purchases") shall be the responsibility of that

Party. Existing Power Purchases and New Long-Term Power Purchases shall be Power Supply Resources of the contracting Party.

6.3 New Short-Term Power Purchases.

(a) Power Purchases contracted for by either Party after the effective date of the Agreement for duration of less than a year ("New Short-Term Power Purchases") shall be treated as follows:

(i) If a New Short-Term Power Purchase is determined after-the-fact to have been economic to both Parties or to neither Party, each Party shall be allocated a percentage of the MWh, capacity costs (if any) and the energy costs associated with such purchase equal to the Party's Native Load for the hours in which purchases are made divided by the sum of both Parties' Native Loads for such hours.

(ii) If a New Short-Term Power Purchase is subsequently determined to be economic to only one Party, the MWh, capacity costs (if any), and the energy costs associated with such purchase shall be allocated to the Party for which the New Short-Term Power Purchase is economic.

(b) The MWh of a New Short-Term Power Purchase that has been allocated to a Party pursuant to Section 6.3(a)(i) or (ii) shall be a Power Supply Resource of that Party. To the extent that a Party incurs energy costs for a New Short-Term Power Purchase that differs from the allocations set forth in Section 6.3(a) (i) or (ii), a transfer payment will be made to reconcile the difference.

6.4 Non-Native Load Sales.

Subject to Sections 7.2 and 7.4(a) each Party shall be responsible for the cost of the energy from its Power Supply Resources that serve Non-Native Load Sales, as determined by the Joint Dispatcher on an after-the-fact basis using production cost modeling.

ARTICLE VII
CALCULATION OF JOINT DISPATCH SAVINGS

7.1 Overview.

(a) For each hour, the energy produced as a result of the Joint Dispatch shall be allocated to the Parties' Native Load obligations, and Non-Native Load Sales. The determination of how much energy is allocated to each Party shall be conducted on an after-the-fact basis as described below. Such energy allocation is solely for the purpose of calculating savings from the Joint Dispatch and the Parties payment obligations under this Article VII.

(b) The least cost energy from each Party's Power Supply Resources shall be applied first to serve its own Native Load obligations. If it is determined after-the-fact that a Party's Power Supply Resources provided energy to serve the other Party's Native Load service obligations or Non-Native Load Sales obligations, then only such provision of energy shall be considered to be a wholesale power transaction between the Parties.

(c) The transfer payments under this Agreement are intended to produce an energy cost for serving each Party's Native Load Customers that is the same as if such Native Load were served by that Party's Power Supply Resources, adjusted by the allocation of costs and savings of the Joint Dispatch as reflected in the payments set forth in Section 7.5.

7.2 Allocation of Energy to Non-Native Load Sales.

For each hour, Non-Native Load Sales shall be deemed to have been satisfied by the highest cost energy from the Parties' Power Supply Resources produced in that hour (other than Must Run Resources).

7.3 Allocation of Energy to Native Load.

After the allocation of energy costs to Non-Native Load Sales has been performed pursuant to Section 7.2, the remaining least cost energy produced in an hour by the Parties' Power Supply Resources shall be deemed to have served the Parties' Native Loads. Each Party's Native Load also shall be allocated the costs of energy produced from its own Must Run Resources. Each Party shall be responsible initially for the energy costs of its Power Supply Resources deemed to have served the Parties Native Loads ("Incurred Native Load Costs").

7.4 Payments for Purchases and Sales of Energy Between the Parties.

For each hour, a payment shall be calculated for the purchase and sale of energy between the Parties as a result of the Joint Dispatch of the Parties' Power Supply Resources. This payment shall be calculated as follows:

(a) Payments for energy sales to meet Non-Native Load Sales

(i) After the fact for each hour, the Joint Dispatcher shall use production cost models to determine, the energy costs allocated to the Non-Native Load Sales pursuant to Sections 6.4 and 7.2. Such energy costs shall be compared to the revenues generated from such sales. This difference, whether positive or negative, will be considered the "Non-Native Load Sales Margin." Each Party shall be entitled to an amount equal to: (1) the energy cost from its Power Supply Resources allocated to the Non-Native Load Sales; (2) plus a percentage of the Non-Native Load Sales Margin equal to the MWh produced by the Party's Power Supply Resources during the hour divided by the total MWh produced by both Parties Power Supply Resources during the hour.

(ii) To the extent that the Parties incur energy costs for and revenues from Non-Native Load Sales that produces a different result than the calculation set forth in Section 7.4 (a)(i), a transfer payment will be made between the Parties to reconcile that difference.

(b) Payments for energy sales related to Native Load.

(i) After the fact, for each hour, the Joint Dispatcher shall use production cost models to determine the cost each Party would have incurred to serve its Native Load without the benefit of Joint Dispatch ("Stand Alone Native Load Costs"). The positive difference between the cost of all Power Supply Resources deemed to have served the Parties' Native Load pursuant to Section 7.3 and the sum of the Parties Stand Alone Native Load Costs shall be the "Native Load Joint Dispatch Savings."

(ii) The Joint Dispatcher shall allocate to each Party a pro rata share of the Native Load Joint Dispatch Savings based on each Party's relative amount of MWh produced by their respective Power Supply Resources in the hour.

(iii) The Joint Dispatcher shall then subtract each Party's allocated share of Native Load Joint Dispatch Savings for the hour from its Stand Alone Native Load Costs for that hour. The resulting cost figure for each Party shall be that Party's "Joint Dispatch Native Load Costs" for the hour.

(iv) The Party whose Joint Dispatch Native Load Costs for an hour are more than its Incurred Native Load Costs for that hour shall owe the other Party a payment for that hour equal to the difference between its Joint Dispatch Native Load Costs and its Incurred Native Load Costs.

The Joint Dispatcher shall sum each Party's payment obligations reduced by its payment entitlements under Sections 7.4(a) and (b) above for that hour. The Party with a positive total shall owe that amount to the other Party as payment for energy sold to it during that hour.

ARTICLE VIII
CAPACITY SALES

8.1 Capacity Sales.

If a Party requires additional capacity for reliability purposes, and the other Party has the ability to supply all or some capacity (with or without accompanying energy), without impacting reliability or service quality to the selling Party's Native Load Customers, then the Joint Dispatcher may enter into a capacity sale on behalf of the selling Party pursuant to the selling Party's then-effective FERC-filed cost-based rate tariff and such sale shall be priced in accordance therewith. However, nothing in this Agreement shall be construed as creating a right in either Party to the capacity of the other Party.

ARTICLE IX
BILLING PROCEDURES

9.1 Records.

The Joint Dispatcher shall maintain such records as may be necessary to determine the assignment of costs savings of Joint Dispatch and the payments required pursuant to this

Agreement. Such records shall be made available to the Parties as reasonably required, including as needed for state and federal regulatory purposes.

9.2 Monthly Statements.

As promptly as practicable after the end of each calendar month, the Joint Dispatcher shall prepare a statement setting forth the monthly summary of costs for which each Party is responsible and revenues from Short-Term Non-Native Load Sales to be allocated to each Party in sufficient detail as may be needed for settlements under the provisions of this Agreement. As required, the Joint Dispatcher may provide such statements on an estimated basis and then adjust those statements for actual results.

9.3 Monthly Bills.

As promptly as practicable after the end of each calendar month, the Joint Dispatcher shall prepare a monthly bill for each Party based on the sum of that Party's payment obligations reduced by its payment entitlements calculated pursuant to Section 7.4. The Joint Dispatcher shall net each Party's hourly payment obligations against its hourly payment entitlements, and render a bill for the differences. The bill for each December shall also state an annual payment amount that nets out each Party's obligations and entitlements for the calendar year.

9.4 Billings and Payments.

The Joint Dispatcher shall handle all billing between the Parties and with other entities with which the Joint Dispatcher engages in activities pursuant to this Agreement. Payment between the Parties shall be by making remittance of the net amount billed or by making appropriate accounting entries on the books of the Parties. Payment of the bills for a calendar year shall be made no later than 30 days after the receipt of the bill for December of that calendar year.

9.5 Taxes.

Should any federal, state, or local tax, surcharge or similar assessment, in addition to those that may now exist, be levied upon the energy dispatched pursuant to the terms of this Agreement or for the Joint Dispatcher's services provided in connection with this Agreement, or upon either of the Parties measured by energy or service, or the revenue therefrom, any such additional amounts shall be included in the net billing as described in Section 9.4.

ARTICLE X
FORCE MAJEURE

10.1 Events Excusing Performance.

Neither Party shall be liable to the other Party for or on account of any loss, damage, injury, or expense resulting from or arising out of a delay or failure to perform, either in whole or in part, any of the agreements or obligations made by or imposed upon the Parties by this Agreement, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel), failure of equipment, environmental restrictions, riot, fire, flood, ice, wind, invasion, civil war, commotion, insurrection, military or usurped power, order of any court granted in any bona fide adverse legal proceedings or action, or of any civil or military authority either de facto or de jure, explosion, Act of God or the public enemies, or any other cause reasonably beyond its control and not attributable to its neglect. A Party experiencing such a delay or failure to perform shall use due diligence to remove the cause or causes thereof; however, no Party shall be required to add to, modify or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action is advisable.

ARTICLE XI
INDUSTRY STANDARDS

11.1 Adherence to Reliability Criteria.

The Parties agree to conform to Industry Standards as they affect the implementation or the Parties' performance of this Agreement.

ARTICLE XII
GENERAL

12.1 No Third Party Beneficiaries.

This Agreement does not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of said Parties. Nothing in this Agreement shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier, other than the Parties, any rights hereunder or in any of the resources or facilities owned or controlled by the Parties or the use thereof.

12.2 Waivers.

Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

12.3 Successors and Assigns.

This Agreement shall inure to the benefit of and be binding only upon the Parties and their respective successors and assigns, and shall not be assignable by any Party without the written consent of the other Party except to a successor in the operation of its properties by reason of a merger, consolidation, sale or foreclosure whereby substantially all such properties are acquired by or merged with those of such a successor, subject to all relevant state and federal regulatory approvals.

12.4 Liability and Indemnification.

Subject to any applicable state or federal law which may specifically restrict limitations on liability, each Party shall release, indemnify, and hold harmless the other Party, its directors, officers and employees from and against any and all liability for loss, damage or expense alleged to arise from, or incidental to, injury to persons and/or damage to property in connection with its facilities or the production or transmission of electric energy by or through such facilities, or related to performance or non-performance of this Agreement, including any negligence arising hereunder. In no event shall any Party be liable to another Party for any indirect, special, incidental or consequential damages with respect to any claim arising out of this Agreement.

12.5 Section Headings.

The descriptive headings of the Articles and Sections of this Agreement are used for convenience only and shall not modify or restrict any of the terms and provisions thereof.

12.6 Notice.

Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date of such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to:

Catherine S. Stempien
Vice President – Legal
Duke Energy Corporation
550 South Tryon Street
Charlotte, NC 28202

David B. Fountain
Vice President – Legal
Progress Energy Service Company, LLC
410 S. Wilmington Street
Raleigh, NC 27601

or in such other form or to such other address as the Parties may stipulate.

ARTICLE XIII
REGULATORY APPROVAL

13.1 Regulatory Authorization.

This effectiveness of this Agreement is subject to and conditioned upon:

(a) Acceptance for filing without material condition or modification by the FERC; and

(b) The Parties obtaining all necessary approvals from state regulatory authorities to consummate the Merger and enter into the Agreement, in all cases without material condition or modification.

13.2 Changes.

It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify or supplement this Agreement to reflect changes in operating practices or costs of operations or for other reasons. Any such changes to this Agreement shall be in writing executed by the Parties, subject to all necessary state and federal regulatory authorizations.

ARTICLE XIV
COMPLIANCE WITH
NCUC REGULATORY ORDERS

14.1 DEC and PEC Regulatory Conditions.

In compliance with NCUC regulatory conditions, the Parties agree as follows:

(a) To the extent Joint Dispatch under this Agreement transfers control of, or operational responsibility for, DEC's generation assets used for the generation of electric power for DEC's North Carolina retail customers, then:

(i) DEC will not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations, and orders of the NCUC promulgated thereunder; and

(ii) DEC will not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

(b) To the extent Joint Dispatch under this Agreement transfers control of, or operational responsibility for, PEC's generation assets used for the generation of electric power for PEC's North Carolina retail customers, then:

(i) PEC will not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations, and orders of the NCUC promulgated thereunder; and

(ii) PEC will not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

DUKE ENERGY CAROLINAS, LLC

By:______________________________
Name: Brett C. Carter
Title: President

PROGRESS ENERGY CAROLINAS, INC.

By:______________________________
Name: Lloyd M. Yates
Title: President and Chief Executive Officer

JOINT DISPATCH AGREEMENT

(MARKED)

JOINT DISPATCH AGREEMENT

BETWEEN

DUKE ENERGY CAROLINAS, LLC

AND

CAROLINA POWER & LIGHT COMPANY

(Duke Energy Carolinas, LLC Rate Schedule No. 341)

Tariff Submitter: Duke Energy Carolinas, LLC
FERC Tariff Program Name: FERC FPA Electric Tariff
Tariff Title: Tariffs, Rate Schedules and Service Agreements
Tariff Record Proposed Effective Date: ~~12/31/9998~~7/2/2012
Tariff Record Title: Joint Dispatch Agreement
Record Content Description: Rate Schedule No. 341
Option Code: A

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JOINT DISPATCH AGREEMENT

THIS JOINT DISPATCH AGREEMENT ("Agreement") is made and entered into as of the ____ day of ___________, 20__, by and between Duke Energy Carolinas, LLC ("DEC"), and Carolina Power and Light Company, doing business as Progress Energy Carolinas, Inc. ("PEC") (collectively referred to herein as the "Parties" and individually as a "Party").

WHEREAS, DEC and PEC are the owners and operators of electric generation, transmission and distribution facilities and are engaged in the business of generating, transmitting, distributing, and selling electric energy to the retail customers in their franchised service areas in North Carolina and South Carolina and also at wholesale to municipalities, cooperatives, and other electric utilities; and

WHEREAS, Duke Energy Corporation, the parent company of DEC, and Progress Energy, Inc., the parent company of PEC, have entered into an Agreement and Plan of Merger dated January 8, 2011 ("Merger"); and

WHEREAS, DEC and PEC intend to jointly dispatch their Power Supply Resources in order to most economically serve the Native Load Customers of both DEC and PEC following the consummation of the Merger; and

WHEREAS, the Parties desire to establish a framework under which the foregoing joint dispatch of the DEC and PEC Power Supply Resources, and the resulting cost savings will be equitably shared between the Parties;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein set forth, the Parties mutually agree as follows:

ARTICLE I
DEFINITIONS

Capitalized terms shall have the meanings set forth below in the Article I. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this Agreement or as commonly used in the electric utility industry.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" or **"BAA"** means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority within which the Balancing Authority maintains the load-resource balance.

~~**"Existing Non-Native Load Sales"** means Non-Native Load Sales made pursuant to obligations entered into prior to the effective date of this Agreement.~~

"Industry Standards" means all applicable national and regional electric reliability council principles, guides, criteria, and standards and industry standard practices.

"Joint Dispatch" means the dispatch of the Power Supply Resources owned by DEC and PEC respectively on a least cost basis as described in Section 3.1.

"Must Run Resources" means generation units or power purchases that are dispatched out of merit order either due to contractual arrangements or to satisfy operational, reliability or regulatory requirements.

"Native Load" means the load of a Party's Retail Native Load Customers and the retail load of its wholesale customers or its wholesale customers' members served by the Party, directly or indirectly, at Native Load Priority.

"Native Load Customers" means a Party's Retail Native Load Customers plus its wholesale customers that have Native Load served by the Party, for which the Party has an obligation pursuant to current or future wholesale contracts, for the length of such contracts, to engage in planning and to sell and deliver electric capacity and energy in a manner comparable to the Party's service to its Retail Native Load Customers.

"Native Load Priority" means a priority of service equivalent to that provided by the Party to its Retail Native Load Customers.

"NCUC" means the North Carolina Utilities Commission.

~~**"New Non-Native Load Sales"** means Non-Native Load Sales entered into after the effective date of this Agreement.~~

"Non-Native Load Sales" means a Party's sales of energy at wholesale, not including transactions between the Parties pursuant to this Agreement or service to Native Load.

"Power Purchases" means purchases of energy at wholesale from sellers other than the other Party.

"Power Supply Resources" means the generating facilities owned by a Party and its Existing Power Purchases and Long Term Power Purchases as further provided herein to be used under this Agreement.

"PSCSC" means the Public Service Commission of South Carolina.

"Retail Native Load Customers" means the retail electric customers for which either DEC or PEC has an obligation under North Carolina and South Carolina law to engage in long-term planning and to supply all generation, transmission, distribution, delivery and sales, and other related services, including installing or contracting for capacity, if needed to provide adequate and reliable service.

"VACAR" means the Virginia-Carolinas sub region within the North American Electric Reliability Corporation's (NERC) SERC Reliability Corporation (SERC).

"VACAR Reserve Sharing Group Arrangement" means the collection of agreements and procedures developed concurrently by the Principals and Operating Representatives of multiple two-party Interchange Agreements as described in the Operating Manual for the VACAR Reserve Sharing Group Arrangement, Revision No. 2, dated January 11, 2011 by and among Dominion, Duke Energy Carolinas, LLC, Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company and South Carolina Public Service Authority, as amended.

ARTICLE II
TERM OF AGREEMENT

2.1 Term.

Subject to approval and any conditions imposed by state and federal regulatory authorities, this Agreement shall take effect upon consummation of the Merger and shall continue in full force and effect for a period of five (5) years from the effective date, continuing thereafter until terminated by mutual agreement of the Parties or by either Party upon five (5) years' written notice to the other Party. If the Parties terminate the Merger prior to its consummation, this Agreement shall have no force or effect.

ARTICLE III
SCOPE OF THE AGREEMENT

3.1 Purpose.

The primary purpose of this Agreement is to provide the contractual basis for the Joint Dispatch of the Power Supply Resources of both DEC and PEC for the purpose of reducing the cost of serving their Native Load Customers to the extent consistent with the provision of reliable electric service, Industry Standards, and applicable laws and regulations ("Joint Dispatch"). This Agreement also shall provide the contractual basis for the sharing of the cost savings resulting from such Joint Dispatch.

3.2 Limits on Scope and Effect of the Agreement.

(a) Nothing in this Agreement is intended to or shall it be construed as:

(i) Providing for or requiring a single integrated electric system;

(ii) Providing for or requiring a single BAA, control area or transmission system;

(iii) Providing for or requiring joint planning or joint development of generation or transmission;

(iv) Providing for or requiring a Party to construct generation or transmission facilities for the benefit of the other Party;

(v) Transferring any rights to generation or transmission facilities from one Party to the other; or

(vi) Providing for or requiring any equalization of the Parties' production costs or rates.

(b) To the extent that the Parties desire to engage in any of the activities or take any of the actions described in Section 3.2 (a), the Parties will amend this Agreement or enter into a separate agreement, subject to approval by the applicable state and federal regulatory authorities.

(c) ~~In addition to the foregoing, DEC and PEC have agreed, in previous proceedings before the NCUC (NCUC Docket E-7, Sub 795 and NCUC Docket E-2, Sub 884, respectively), to insert into any affiliate agreements such as this Agreement the following provisions:~~

~~(i)~~ The participation by both DEC and PEC in this Agreement is voluntary, neither DEC nor PEC is obligated to participate in this Agreement or to make any purchases or sales pursuant thereto and the participation of both DEC and PEC in this Agreement is subject to termination, after notice is provided pursuant to Section 2.1 of this Agreement;

~~(ii) Neither DEC nor PEC may make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder;~~

~~(iii) Neither DEC nor PEC may seek to reflect in its North Carolina retail rates (i) any costs incurred under this Agreement exceeding the amount allowed by the NCUC or (ii) any revenue level earned under the Agreement other than the amount imputed by the NCUC; and~~

~~(iv) Neither DEC nor PEC will assert in any forum that the NCUC's authority to assign, allocate, make pro forma adjustments to or disallow revenues or costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and DEC and PEC will bear the full risk of any preemptive effects of federal law with respect to this Agreement.~~

ARTICLE IV
THE JOINT DISPATCHER

4.1 Joint Dispatch Function.

DEC shall act as the Joint Dispatcher, on behalf of DEC and PEC, and shall have the following responsibilities:

(a) Directing the dispatch of both DEC's and PEC's Power Supply Resources;

(b) Making Power Purchases for durations of less than one year ("New Short-Term Power Purchases") to serve the Parties' Native Loads and making Non-Native Load Sales for durations of less than one year from the Parties' Power Supply Resources to the benefit of each Party's Native Load Customers;

(c) Developing and providing bills and billing-related information to effectuate the terms of this Agreement;

(d) Such other activities and duties as may be assigned from time to time by the mutual agreement of the Parties, including but not limited to administration of demand-side resources on behalf of the Parties, subject to applicable state and federal regulatory approvals; and

(e) Incurring the costs necessary to perform its responsibilities under this Agreement, subject to applicable state and federal regulatory approvals.

ARTICLE V
JOINT DISPATCH OF POWER SUPPLY RESOURCES

5.1 Joint Dispatch.

As soon as practicable after the effective date of the Merger, the Joint Dispatcher shall direct the dispatch of the Parties' Power Supply Resources in a manner that: (a) ensures the reliable fulfillment of each Party's service obligations to its Native Load Customers; (b) minimizes the total costs incurred to fulfill each Party's service obligations to its Native Load Customers; and (c) economically satisfies any obligations of each of the Parties with respect to Non-Native Load Sales. To these ends, the Joint Dispatcher shall direct the dispatch of the Power Supply Resources of both Parties consistent with Industry Standards for the safe and reliable operation of both of the Parties' electric systems, the safe and reliable operation of both of the Parties' generating resources, and all applicable laws and regulations, including but not limited to the applicable rules, regulations, orders, and conditions of the NCUC, the PSCSC, the

Federal Energy Regulatory Commission ("FERC"), the North American Electric Reliability Corporation ("NERC"), and the SERC Reliability Corporation ("SERC").

5.2 Compliance with Contractual and Regulatory Obligations.

Nothing in this Agreement is intended to diminish or alter the jurisdiction or authority of the NCUC or the PSCSC over the Parties, including, among other things, the jurisdiction and authority to establish the retail rates on a bundled basis for each of the Parties, to impose regulatory accounting and reporting requirements, to impose service quality standards, to require each of the Parties to engage separately in least cost integrated resource planning, or to issue certificates of public convenience and necessity for new generating resources. In addition, nothing in this Agreement is intended to alter the Parties' contractual or regulatory obligations or to provide for Joint Dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following:

(a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and to its other Native Load Customers, and PEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and it its other Native Load Customers;

(b) DEC's obligation to serve its Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales;

(c) PEC's obligation to serve its Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales;

(d) All of DEC's and PEC's respective obligations under wholesale purchase contracts, including contracts for the purchase of energy and capacity on a non-dispatchable basis;

(e) All of DEC's and PEC's respective obligations under wholesale sales contracts, including obligations under full and partial requirements sales contracts;

(f) All of DEC's and PEC's respective obligations under reliability exchange agreements existing prior to the effective date of this Agreement;

(g) DEC's and PEC's respective transmission rights and obligations, including rights and obligations under any transmission service agreements or transmission tariffs and their respective obligations to provide transmission services and to act as the BA for their respective BAAs;

(h) DEC's and PEC's respective individual obligations under the VACAR Reserve Sharing Group Arrangement; and

(i) DEC's and PEC's respective obligations with respect to Must Run Resources to ensure that they are not dispatched in a manner inconsistent with the contractual, operational, reliability or regulatory requirements applicable to such Must Run Resources.

ARTICLE VI
POWER SUPPLY RESOURCES AND NON-NATIVE LOAD SALES

6.1 Generating Resources.

As of the effective date of this Agreement, all generating resources including those that begin commercial operation after the effective date of this Agreement shall be a Power Supply Resource of the Party that owns it and that Party shall be responsible for the capacity costs and energy costs of such Power Supply Resources. If the Parties are subsequently allowed to develop future generating resources jointly or to enter into a reserve sharing agreement with respect to future generating resources, the Parties, at the time that they enter into such an arrangement, and subject to the receipt of all relevant state and federal regulatory approvals, shall agree, upon the allocation of the generation that is the subject of that arrangement for purposes of determining the Parties' Power Supply Resources and responsibility for capacity costs and energy costs.

6.2 Existing Power Purchases and New-Long Term Power Purchases.

The capacity costs (if any) and energy costs associated with Power Purchases contracted for by a Party prior to the effective date of this Agreement ("Existing Power Purchases") and with Power Purchases contracted for by a party after the effective date of this Agreement that are for a year or longer ("New Long-Term Power Purchases") shall be the responsibility of that Party. Existing Power Purchases and New Long-Term Power Purchases shall be Power Supply Resources of the contracting Party.

6.3 New Short-Term Power Purchases.

(a) Power Purchases contracted for by either Party after the effective date of the Agreement for duration of less than a year ("New Short-Term Power Purchases") shall be treated as follows:

(i) If a New Short-Term Power Purchase is determined after-the-fact to have been economic to both Parties or to neither Party, each Party shall be allocated a percentage of the MWh, capacity costs (if any) and the energy costs associated with such purchase equal to the Party's Native Load for the hours in which purchases are made divided by the sum of both Parties' Native Loads for such hours.

(ii) If a New Short-Term Power Purchase is subsequently determined to be economic to only one Party, the MWh, capacity costs (if any), and the energy costs associated with such purchase shall be allocated to the Party for which the New Short-Term Power Purchase is economic.

(b) The MWh of a New Short-Term Power Purchase that has been allocated to a Party pursuant to Section 6.3(a)(i) or (ii) shall be a Power Supply Resource of that Party. To the extent that a Party incurs energy costs for a New Short-Term Power Purchase that differs from the allocations set forth in Section 6.3(a) (i) or (ii), a transfer payment will be made to reconcile the difference.

~~6.4 Existing Non-Native Load Sales.~~

~~Existing Non-Native Load Sales shall be the responsibility of the Party that has contracted for each such sale and are subject to the energy and cost allocation provisions of Section 7.3 and 7.5(b).~~

6.4 ~~New~~ Non-Native Load Sales.

Subject to Sections 7.2 and 7.~~5~~4~~(a)~~ each Party shall be responsible for the cost of the energy from its Power Supply Resources that serve ~~New~~ Non-Native Load Sales, as determined by the Joint Dispatcher on an after-the-fact basis using production cost modeling.

ARTICLE VII
CALCULATION OF JOINT DISPATCH SAVINGS

7.1 Overview.

(a) For each hour, the energy produced as a result of the Joint Dispatch shall be allocated to the Parties' Native Load obligations, ~~Existing Non-Native Load Sales,~~ and ~~New~~ Non-Native Load Sales. The determination of how much energy is allocated to each Party shall be conducted on an after-the-fact basis as described below. Such energy allocation is solely for the purpose of calculating savings from the Joint Dispatch and the Parties payment obligations under this Article VII.

(b) The least cost energy from each Party's Power Supply Resources shall be applied first to serve its own Native Load obligations. If it is determined after-the-fact that a Party's Power Supply Resources provided energy to serve the other Party's Native Load service obligations or Non-Native Load Sales obligations, then only such provision of energy shall be considered to be a wholesale power transaction between the Parties.

(c) The transfer payments under this Agreement are intended to produce an energy cost for serving each Party's Native Load Customers that is the same as if such Native Load were served by that Party's Power Supply Resources, adjusted by the allocation of costs and savings of the Joint Dispatch as reflected in the payments set forth in Section 7.~~5~~4.

7.2 Allocation of Energy to ~~New~~ Non-Native Load Sales.

For each hour, ~~New~~ Non-Native Load Sales shall be deemed to have been satisfied by the highest cost energy from the Parties' Power Supply Resources produced in that hour (other than Must Run Resources).

~~7.3 Allocation of Energy to Existing Non-Native Load Sales.~~

~~To the extent that a Party has, in an hour, an Existing Non-Native Load Sales pursuant to Section 6.4, such Existing Non-Native Load Sales shall be deemed to have been satisfied by the next highest cost energy (other than from Must Run Resources) available after the allocation of energy to New Non-Native Load Sales pursuant to Section 7.2. Each Party shall be responsible initially for the energy cost of its Power Supply Resources deemed to have served the Parties' Existing Non-Native Load Sales ("Incurred Existing Non-Native Load Sales Costs").~~

7.3 Allocation of Energy to Native Load.

After the allocation of energy costs to Non-Native Load Sales has been performed pursuant to Sections 7.2~~-and 7.3~~, the remaining least cost energy produced in an hour by the Parties' Power Supply Resources shall be deemed to have served the Parties' Native Loads. Each Party's Native Load also shall be allocated the costs of energy produced from its own Must Run Resources. Each Party shall be responsible initially for the energy costs of its Power Supply Resources deemed to have served the Parties Native Loads ("Incurred Native Load Costs").

7.4 Payments for Purchases and Sales of Energy Between the Parties.

For each hour, a payment shall be calculated for the purchase and sale of energy between the Parties as a result of the Joint Dispatch of the Parties' Power Supply Resources. This payment shall be calculated as follows:

(a) Payments for energy sales to meet ~~New~~ Non-Native Load Sales

(i) After the fact for each hour, the Joint Dispatcher shall use production cost models to determine, the energy costs allocated to the ~~New~~ Non-Native Load Sales pursuant to Section 6.4~~5 and 7.2~~.and 7.2.~~-~~ Such energy costs shall be compared to the revenues generated from such sales. This difference, whether positive or negative, will be considered the "Non-Native Load Sales Margin." Each Party shall be entitled to an amount equal to: (1) the energy cost from its Power Supply Resources allocated to the ~~New~~ Non-Native Load Sales; (2) plus a percentage of the Non-Native Load Sales Margin equal to the MWh produced by the Party's Power Supply Resources during the hour divided by the total MWh produced by both Parties Power Supply Resources during the hour.

(ii) To the extent that the Parties incur energy costs for and revenues from ~~New~~ Non-Native Load Sales that produces a different result than the calculation set forth in Section 7.~~5~~4 (a)(i)~~(i)~~, a transfer payment will be made between the Parties to reconcile that difference.

~~(b) Payments for energy sales to meet Existing Non-Native Load Sales.~~

~~(i) After the fact, for each hour, the Joint Dispatcher shall use production cost models to determine the cost that a Party would have incurred to satisfy its Existing Non-Native Load Sales without the benefit of Joint Dispatch ("Stand Alone Existing Non-Native Load Sales Cost"). The positive difference between the cost of all Power Supply Resources deemed to have satisfied Existing Non-Native Load Sales determined pursuant to Section 7.3 and the sum of the Parties' Stand Alone Existing Non-Native Load Sales Costs shall be the "Existing Non-Native Load Sales Joint Dispatch Savings."~~

~~(ii)The Joint Dispatcher shall allocate to each Party a pro rata share of the Existing Non-Native Load Sales Joint Dispatch Savings based on each Party's relative amount of MWh produced by their respective Power Supply Resources in the hour.~~

~~(iii)The Joint Dispatcher shall then subtract each Party's allocated share of Existing Non-Native Load Sales Joint Dispatch Savings for the hour from its Stand Alone Existing Non-Native Load Sales Costs for that hour. The resulting cost figure for each Party shall be that Party's "Joint Dispatch Existing Non-Native Load Sales Costs" for the hour.~~

~~(iv)The Party whose Joint Dispatch Existing Non-Native Load Sales Costs for an hour are more than its Incurred Non-Native Load Sales Costs for that hour shall owe the other Party a payment for that hour equal to the difference between its Joint Dispatch Existing Non-Native Load Sales Costs and its Incurred Existing Non-Native Load Sales Costs.~~

~~(c)~~(b) Payments for energy sales related to Native Load.

(i) After the fact, for each hour, the Joint Dispatcher shall use production cost models to determine the cost each Party would have incurred to serve its Native Load without the benefit of Joint Dispatch ("Stand Alone Native Load Costs"). The positive difference between the cost of all Power Supply Resources deemed to have served the Parties' Native Load pursuant to Section 7.~~4~~3 and the sum of the Parties Stand Alone Native Load Costs shall be the "Native Load Joint Dispatch Savings."

(ii) The Joint Dispatcher shall allocate to each Party a pro rata share of the Native Load Joint Dispatch Savings based on each Party's relative amount of MWh produced by their respective Power Supply Resources in the hour.

(iii) The Joint Dispatcher shall then subtract each Party's allocated share of Native Load Joint Dispatch Savings for the hour from its Stand Alone Native Load Costs for that hour. The resulting cost figure for each Party shall be that Party's "Joint Dispatch Native Load Costs" for the hour.

(iv) The Party whose Joint Dispatch Native Load Costs for an hour are more than its Incurred Native Load Costs for that hour shall owe the other Party a payment for that hour equal to the difference between its Joint Dispatch Native Load Costs and its Incurred Native Load Costs.

The Joint Dispatcher shall sum each Party's payment obligations reduced by its payment entitlements under Sections 7.~~5~~4(a) and~~,~~ (b) ~~and (c)~~ above for that hour. The Party with a positive total shall owe that amount to the other Party as payment for energy sold to it during that hour.

ARTICLE VIII
CAPACITY SALES

8.1 Capacity Sales.

If a Party requires additional capacity for reliability purposes, and the other Party has the ability to supply all or some capacity (with or without accompanying energy), without impacting reliability or service quality to the selling Party's Native Load Customers, then the Joint Dispatcher may enter into a capacity sale on behalf of the selling Party pursuant to the selling Party's then-effective FERC-filed cost-based rate tariff and such sale shall be priced in accordance therewith. However, nothing in this Agreement shall be construed as creating a right in either Party to the capacity of the other Party.

ARTICLE IX
BILLING PROCEDURES

9.1 Records.

The Joint Dispatcher shall maintain such records as may be necessary to determine the assignment of costs savings of Joint Dispatch and the payments required pursuant to this Agreement. Such records shall be made available to the Parties as reasonably required, including as needed for state and federal regulatory purposes.

9.2 Monthly Statements.

As promptly as practicable after the end of each calendar month, the Joint Dispatcher shall prepare a statement setting forth the monthly summary of costs for which each Party is responsible and revenues from Short-Term Non-Native Load Sales to be allocated to each Party in sufficient detail as may be needed for settlements under the provisions of this Agreement. As required, the Joint Dispatcher may provide such statements on an estimated basis and then adjust those statements for actual results.

9.3 Monthly Bills.

As promptly as practicable after the end of each calendar month, the Joint Dispatcher shall prepare a monthly bill for each Party based on the sum of that Party's payment obligations reduced by its payment entitlements calculated pursuant to Section 7.~~5~~4. The Joint Dispatcher shall net each Party's hourly payment obligations against its hourly payment entitlements, and render a bill for the differences. The bill for each December shall also state an annual payment amount that nets out each Party's obligations and entitlements for the calendar year.

9.4 Billings and Payments.

The Joint Dispatcher shall handle all billing between the Parties and with other entities with which the Joint Dispatcher engages in activities pursuant to this Agreement. Payment between the Parties shall be by making remittance of the net amount billed or by making appropriate accounting entries on the books of the Parties. Payment of the bills for a calendar year shall be made no later than 30 days after the receipt of the bill for December of that calendar year.

9.5 Taxes.

Should any federal, state, or local tax, surcharge or similar assessment, in addition to those that may now exist, be levied upon the energy dispatched pursuant to the terms of this Agreement or for the Joint Dispatcher's services provided in connection with this Agreement, or upon either of the Parties measured by energy or service, or the revenue therefrom, any such additional amounts shall be included in the net billing as described in Section 9.4.

ARTICLE X
FORCE MAJEURE

10.1 Events Excusing Performance.

Neither Party shall be liable to the other Party for or on account of any loss, damage, injury, or expense resulting from or arising out of a delay or failure to perform, either in whole or in part, any of the agreements or obligations made by or imposed upon the Parties by this Agreement, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel), failure of equipment, environmental restrictions, riot, fire, flood, ice, wind, invasion, civil war, commotion, insurrection, military or usurped power, order of any court granted in any bona fide adverse legal proceedings or action, or of any civil or military authority either de facto or de jure, explosion, Act of God or the public enemies, or any other cause reasonably beyond its control and not attributable to its neglect. A Party experiencing such a delay or failure to perform shall use due diligence to remove the cause or causes thereof; however, no Party shall be required to add to, modify or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action is advisable.

ARTICLE XI
INDUSTRY STANDARDS

11.1 Adherence to Reliability Criteria.

The Parties agree to conform to Industry Standards as they affect the implementation or the Parties' performance of this Agreement.

ARTICLE XII
GENERAL

12.1 No Third Party Beneficiaries.

This Agreement does not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of said Parties. Nothing in this Agreement shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier, other than the Parties, any rights hereunder or in any of the resources or facilities owned or controlled by the Parties or the use thereof.

12.2 Waivers.

Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

12.3 Successors and Assigns.

This Agreement shall inure to the benefit of and be binding only upon the Parties and their respective successors and assigns, and shall not be assignable by any Party without the written consent of the other Party except to a successor in the operation of its properties by reason of a merger, consolidation, sale or foreclosure whereby substantially all such properties are acquired by or merged with those of such a successor, subject to all relevant state and federal regulatory approvals.

12.4 Liability and Indemnification.

Subject to any applicable state or federal law which may specifically restrict limitations on liability, each Party shall release, indemnify, and hold harmless the other Party, its directors, officers and employees from and against any and all liability for loss, damage or expense alleged to arise from, or incidental to, injury to persons and/or damage to property in connection with its facilities or the production or transmission of electric energy by or through such facilities, or related to performance or non-performance of this Agreement, including any negligence arising hereunder. In no event shall any Party be liable to another Party for any indirect, special, incidental or consequential damages with respect to any claim arising out of this Agreement.

12.5 Section Headings.

The descriptive headings of the Articles and Sections of this Agreement are used for convenience only and shall not modify or restrict any of the terms and provisions thereof.

12.6 Notice.

Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date of such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to:

Catherine S. Stempien
Vice President – Legal
Duke Energy Corporation
550 South Tryon Street
Charlotte, NC 28202

David B. Fountain
Vice President – Legal
Progress Energy Service Company, LLC
410 S. Wilmington Street
Raleigh, NC 27601

or in such other form or to such other address as the Parties may stipulate.

ARTICLE XIII
REGULATORY APPROVAL

13.1 Regulatory Authorization.

This effectiveness of this Agreement is subject to and conditioned upon:

(a) Acceptance for filing without material condition or modification by the FERC; and

(b) The Parties obtaining all necessary approvals from state regulatory authorities to consummate the Merger and enter into the Agreement, in all cases without material condition or modification.

13.2 Changes.

It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify or supplement this Agreement to reflect changes in operating practices or costs of operations or for other reasons. Any such changes to this Agreement shall be in writing executed by the Parties, subject to all necessary state and federal regulatory authorizations.

ARTICLE XIV
COMPLIANCE WITH
NCUC REGULATORY ORDERS

14.1 DEC and PEC Regulatory Conditions.

In compliance with NCUC regulatory conditions, the Parties agree as follows:

(a) To the extent Joint Dispatch under this Agreement transfers control of, or operational responsibility for, DEC's generation assets used for the generation of electric power for DEC's North Carolina retail customers, then:

(i) DEC will not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations, and orders of the NCUC promulgated thereunder; and

(ii) DEC will not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

(b) To the extent Joint Dispatch under this Agreement transfers control of, or operational responsibility for, PEC's generation assets used for the generation of electric power for PEC's North Carolina retail customers, then:

(i) PEC will not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations, and orders of the NCUC promulgated thereunder; and

(ii) PEC will not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

DUKE ENERGY CAROLINAS, LLC

By:______________________________
Name: Brett C. Carter
Title: President

PROGRESS ENERGY CAROLINAS, INC.

By:______________________________
Name: Lloyd M. Yates
Title: President and Chief Executive Officer